Energy Price Limits for the Wholesale Electricity Market in Western Australia

AUSTRALIAN ENERGY MARKET OPERATOR

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Contents

Executive Summary

Energy Price Limits are the price ceilings of the Wholesale Electricity Market (WEM) for offers submitted by Market Generators into the Short Term Electricity Market (STEM) and the Balancing Market. There are three types of Energy Price Limits called the Maximum STEM Price, the Alternative Maximum STEM Price and the Minimum STEM Price. The Maximum STEM Price applies to Facilities that are not running on liquid-fuel, and as such it is determined by assessing the cost of gas-fired generation. The Alternative Maximum STEM Price is higher than the Maximum STEM Price because it applies to Facilities running on liquid fuel and is determined by assessing the cost of distillate-fired generation. The Minimum STEM Price is fixed at -$1,000/MWh and is not being reviewed in this study.

Once a year, the Australian Energy Market Operator (AEMO) is required to review the Energy Price Limits in the WEM. The formula for calculating the Energy Price Limits is stated in the Market Rules as:

(1 + Risk Margin) x (Variable O&M + (Heat Rate x Fuel Cost))/Loss Factor

where:

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine (OCGT) generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW OCGT generating station expressed in $/MWh, and includes, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW OCGT generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW OCGT generating station, expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW OCGT generating station relative to the Reference Node.

The Market Rules state that the above variables should be determined for “a 40 MW open cycle gas turbine generating station”. Previous analysis of Energy Price Limits has shown that the Pinjar 40 MW gas turbines (GTs) have the highest cost for short dispatch periods and the Parkeston aero-derivative gas turbines are the next most costly to run for peaking purposes. These are therefore the machines that have been chosen to assess the Energy Price Limits.

Jacobs was engaged by AEMO to conduct the 2016 review for the year commencing 1 July 2016. This assignment was conducted in a similar fashion to that conducted by Jacobs in 2015. Jacobs’ methodology in assessing the above formula hinges on the fact that uncertainty surrounds all of the variables in the above Energy Price Limits formula, with the exception of the Loss Factor, which is a fixed number that is known in advance. Jacobs’s approach is to represent the uncertainty around each variable with an appropriate probability distribution, and then perform Monte Carlo simulations which yield a distribution of output prices.

The Energy Price Limit for the Maximum STEM price is chosen as the 80th percentile of the output price distribution, where an appropriate gas price distribution has been used to represent the fuel cost. The Risk Margin is an output of this assessment and is chosen to be the difference between the mean and the 80th percentile of the output price distribution.

A slightly different approach is used to determine the Alternative Maximum STEM price compared to the determination of the Maximum STEM price. The 80th percentile cost of the above formula is calculated for a fixed distillate price over all Monte Carlo samples, and this calculation is repeated over an appropriate range of distillate prices. This enables a regression equation to be determined with a fuel independent (“non-fuel”) component plus a “fuel” cost component that is proportional to the net ex terminal distillate price. Each month the Alternative Maximum STEM price is determined by substituting the current net ex terminal distillate price into the regression equation.

For the 2016 review, Jacobs has:

- Continued with the basis for setting the Energy Price Limits as applied in 2015;

- Updated the O&M costs for operating 40 MW gas turbines for both the industrial and aero-derivative types by accounting for movements in foreign exchange rates and applying CPI cost escalation;
- Retained assumptions on average heat rates at maximum and minimum capacity from the 2015 review;
- Slightly modified the approach to projecting the gas price distribution to account for expected movements in the contract market that are also expected to flow through to the spot market;
  - In this year's analysis the gas price projection was based only on the historical maximum monthly spot gas price time series;
  - The time series forecasting approach was adjusted for the unusually low spot gas prices and to reflect the recent upwards trend in the gas contract price which also has an influence on the spot price. Jacobs further explored factors influencing the spot gas price and a reasonably strong correlation (with a correlation coefficient of 0.57) was found to exist between the Brent crude oil price denominated in US dollars and the historical maximum monthly spot gas prices in WA. With the expectation that the recent upwards trend in the Brent crude oil price will continue in the short to medium term, Jacobs considered it reasonable to add an uptrend to the maximum monthly spot gas price forecast to represent the expected movement in the oil price.
  - Jacobs has applied a pass through of 50% of the expected movement in the contract gas price[1] through to the maximum monthly spot gas price. The limitation to 50% is due to the imperfect correlation between the Brent crude oil price and the maximum monthly spot gas price and also not to pass through other factors influencing contract prices that do not necessarily impact on spot gas prices. The net result of this adjustment was to add $0.46/GJ onto the mean of the forecast spot gas price distribution.
- Used the following gas pricing parameters deemed applicable to the spot purchase and transport of gas for peaking purposes:
  - Defined the daily load factor to have an 80% confidence range between 80% and 98% using a truncated lognormal distribution, with a mean value of 89.9%, and a most likely value of 95.0%;
  - Sampled from the gas commodity cost distribution between $2/GJ and $19.6/GJ[2] with an 80% confidence range of $4.80/GJ to $10.25/GJ, a mean value of $7.57/GJ and a most probable value of $7.30/GJ;
  - Used a lognormal distribution of spot gas transport cost to the Perth area between $1.00/GJ and $3.00/GJ with an 80% confidence range between $1.46/GJ and $2.15/GJ, a mean value of $1.796/GJ and a mode of $1.736/GJ;
- Used historical market observations from the 2014 and 2015 calendar years to estimate distributions for starting frequency, average run time, generation per Dispatch Cycle and minimum capacity for Pinjar and Parkeston;
- Continued the previous treatment of start-up costs and cost uncertainty. The recommended price is set to cover 80% of possible outcomes with run times of between 0.5 and 6 hours;
- Continued to use the standard deviation of daily Singapore gasoil prices to assess the variation in distillate price since it is the Singapore gasoil price that is used to estimate the Ex Terminal price in the analysis. The uncertainty and level of the distillate price is relevant to the extent that it is used to cap the extreme spot gas prices at the level where the Dispatch Cycle cost would be equal for gas and for distillate firing for the nominated gas turbine technology and location. Hence variation in distillate price is used in determining the Maximum STEM Price, not the Alternative Maximum STEM Price.
- Extended the Monte Carlo sampling from 1,000 samples to 10,000 samples, thereby reducing the standard error of estimated quantities by a factor of 3.16 relative to last year's analysis.

Exec Table 1 shows the calculation of the Energy Price Limits in accordance with the structure defined in clause 6.20.7(b) of the Market Rules.

[1] Source from IMO, *Gas Statement of Opportunities*, Nov 2015, p.90.

[2] Note that the maximum gas price was simulated up to a break-even price with the use of distillate in the generation plant assuming dual fuel capability.

Exec Table 1 Summary Parameters defined in Clause 6.20.7 (b)

Component	Units	Maximum STEM Price	Alternative Maximum STEM Price
Mean Variable O&M	$/MWh	$57.18	$57.18
Mean Heat Rate	GJ/MWh	19.047	19.098
Mean Fuel Cost	$/GJ	$7.57	$13.89
Loss Factor		1.0298	1.0298
Before Risk Margin 6.20.7(b) [3]	$/MWh	$195.54	$313.12
Risk Margin added	$/MWh	$44.46	$33.88
Risk Margin Value	%	22.7%	10.8%
Assessed Maximum Price	$/MWh	$240	$347

Exec Table 2 summarises the prices that have applied since November 2011 and the subsequent results obtained by using the various methods. New values are rounded to the nearest dollar which is consistent with previous practice.

Exec Table 2 Summary of price cap analysis

No.	History of proposed and published prices	Maximum STEM Price ($/MWh)	Alternative Maximum STEM Price ($/MWh)	Comment
1	Published Prices from 1 November 2011	$314	$533	From AEMO website.
2	Published Prices from 1 July 2012	$323	$547	From AEMO website.
3	Published Prices from 1 July 2013	$305	$500	From AEMO website
4	Published Prices from 1 July 2014	$330	$562	From AEMO website
6	Published Price from 1 July 2015	$253	$429	From AEMO website
7	Published Price from 1 June 2016	$253	$315	From AEMO website[4]
8	Proposed price to apply from 1 July, 2016	$240	$347	Based on $13.56/GJ for distillate, ex terminal.
9	Probability level as Risk Margin basis	80%	80%	

Notes: (1) In row 8, as required in clause 6.20.7(b) these are the proposed price caps to apply from 1 July 2016 based on a projected Net Ex Terminal wholesale distillate price of $0.926/litre excluding GST ($13.56/GJ).
(2) In row 9, the probability levels that are proposed to be applied to determine the Risk Margin for setting the price caps in accordance with the Market Rules.

The recommended values are $240/MWh for the Maximum STEM Price and $347/MWh for the Alternative Maximum STEM Price at $13.56/GJ Net Ex Terminal distillate price (i.e. net of excise rebate and excluding GST).

[3] Mean values have been rounded to the values shown in the Table for the purpose of this calculation.
[4] http://wa.aemo.com.au/home/electricity/market-information/price-limits, last accessed 3 June 2016.

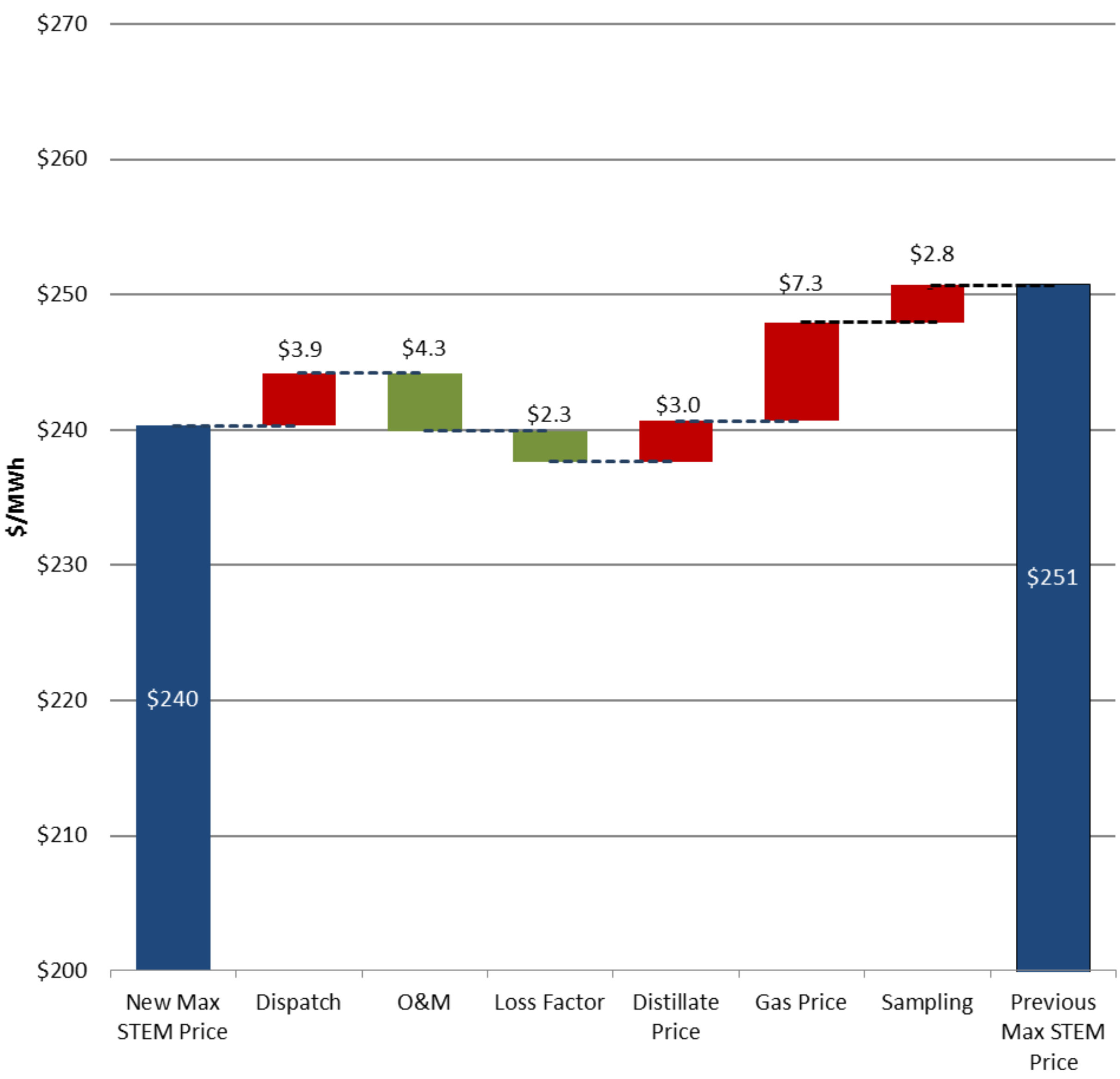
The price components for the Alternative Maximum STEM Price are:

> $84.27/MWh + 19.356 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

The largest factor accounting for the decrease in the Maximum STEM Price since last year's assessment is the downward movement in the forecast gas price. Secondary factors in the decrease are the increase in the O&M cost, due to the lower exchange rate, CPI escalation and shorter Dispatch Cycle and also a decrease in the Dispatch Cycle cost, which reflects lower start cost (due to the lower fuel usage), but high non-fuel costs which are spread out over lower dispatch levels. The secondary factors are similar in magnitude, but affect the Maximum STEM price in opposite directions and therefore almost cancel each other out.

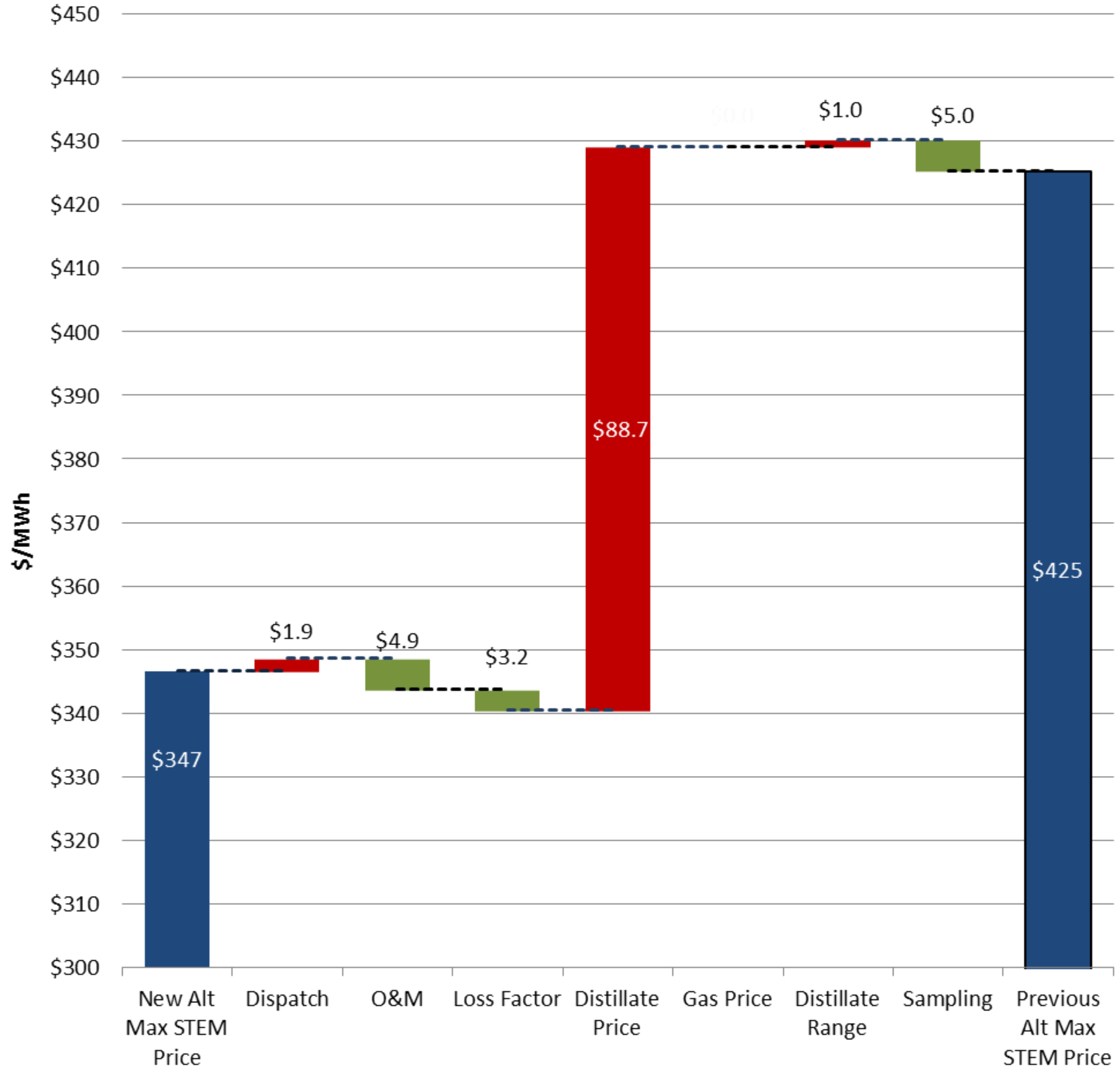
The contributions to the change in the Maximum STEM Price relative to last year's analysis are illustrated in the waterfall diagram in Exec Figure 1.

Exec Figure 1 Impact of factors on the change in the Maximum STEM Price since 2015



The decrease in the Alternative Maximum STEM Price is primarily due to the decrease in the oil price, coupled with downward movement in the $AU:$US exchange rate. Lesser factors influencing the final outcome are the increase in the number of Monte Carlo samples, the increase in the O&M cost and the loss factor. The contributions to the change in the Alternative Maximum STEM Price relative to last year's analysis are illustrated in the waterfall diagram in Exec Figure 2.

Exec Figure 2 Impact of factors on the change in the Alternative Maximum STEM Price since 2015



Definitions

To assist the reader this section explains some of the terminology used in the Report.

Term	Explanation
Dispatch Cycle cost	This term is used to describe the parameter calculated to determine the Energy Price Limits. It is the total cost of dispatch of a start-up and shut-down cycle of a peaking gas turbine divided by the amount of electrical energy in MWh generated during the Dispatch Cycle.
Break-even gas price	In simulating the gas price distribution, the delivered gas price was reduced if necessary to make the sampled value of the Dispatch Cycle cost equal to the Dispatch Cycle cost for running on distillate, allowing for the impact on relative operating costs and thermal efficiency on both fuels. It was not based on the equivalent heat content of distillate alone.
Carbon price	The previous federal government legislated a carbon pricing mechanism from 1 July 2012 with an initial carbon price of $23/t CO_2e, a price from 1 July 2013 of $24.15/ t CO_2e and a price from 1 July 2014 of $25.40/ t CO_2e. The current federal government repealed this legislated carbon price effective from 1 July 2014.
Dispatch Cycle	The process of starting a generating plant, synchronising it to the electricity system, loading it up to minimum load as quickly as possible, changing its loading between minimum and maximum levels to meet system loading requirements, running it down to minimum load and then to zero for shut-down.
Energy Price Limits	The Maximum STEM Price and the Alternative Maximum STEM Price as specified in the Market Rules.
Net Ex Terminal Price	Wholesale price for distillate in Perth, Western Australia, after deduction of excise rebate and excluding GST. This price does not include road freight costs.
Margin	The difference between the price caps as set by AEMO and the expected value of the highest short run costs of peaking power.
Market Dispatch Cycle Cost Method	A method for calculating the fuel consumption over a dispatch period of a peaking gas turbine that represents various levels of loading consistent with a specified capacity factor. This is an alternative method to specifying a particular heat rate basis irrespective of dispatch conditions.
Market Rules	The rules used to conduct the operation of the Western Australian Wholesale Electricity Market (WEM) as gazetted and amended. The current version of the rules was issued on 30 November 2015 and may be found at http://wa.aemo.com.au/home/imo/rules/wem-rules
Risk Margin	The difference between the price caps as set by AEMO and a function of the expected values of variable O&M costs, heat rate and fuel cost as specified in clause 6.20.7(b) of the Market Rules. The Risk Margin is intended to allow for the uncertainty faced by AEMO in setting the price caps, or (in the case of the Alternative Maximum STEM price) its fuel and non-fuel price components.
Short run marginal cost (SRMC)	The additional cost of producing one more unit of output from existing plant. In the context of this report it refers to the increase in the total production cost arising from the production of one extra unit of electricity and is measured in dollars per megawatt hour ($/MWh).
Short run (average) cost	The cost of starting a generating unit, running it to produce electricity for a short period of time (usually less than 12 hours) and then shutting it down divided by the amount of electricity produced during that period of operation. This is measured in $/MWh.
Short Term Energy Market (STEM)	A day ahead contract market that is operated by AEMO, to allow buyers and sellers of electricity to adjust their contract positions on a day to day basis to allow for variations in demand and plant performance and to reduce exposure to the Balancing Market arising from mismatch between supply (for generators) or demand (for retailers) and their contract position.
Synchronisation	Refers to the point in time when a generating unit is connected to the electricity network so that it can be subsequently loaded up to supply power to the electricity system.

Term	Explanation
Type A gas turbine maintenance	Frequent annual preventative maintenance which may only take a few days and does not require major part replacement. Such maintenance is typically undertaken after 12,000 running hours or some 600 unit starts.
Type B gas turbine maintenance	Hot section refurbishment / intermediate overhaul – typically carried out at around 24,000 running hours or 1200 starts. Major thermally stressed operating parts are often replaced.
Type C gas turbine maintenance	Major overhaul of thermally stressed and rotating parts of the gas turbine. Typically undertaken after 48,000 running hours or 2400 unit starts.
WEM	Wholesale Electricity Market as operated by AEMO.

Important note about this report

The sole purpose of this report and the associated services performed by Jacobs is to review the Energy Price Limits to apply in the Wholesale Electricity Market for the year commencing 1 July 2016 in accordance with the scope of services set out in the contract between Jacobs and the Client. That scope of services, as described in this report, was developed with the Client.

In preparing this report, Jacobs has relied upon, and presumed accurate, any information (or confirmation of the absence thereof) provided by the Client and/or from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

Jacobs derived the data in this report from information sourced from the Client (if any) and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Jacobs has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

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1. Introduction

1.1 Review of maximum prices

As part of the market power mitigation strategy for the WEM, there are price caps which limit the prices that may be paid in the STEM and Balancing Market. The maximum price depends on whether gas or liquid fuelled generation is required to meet the electricity demand when the maximum price applies. The Alternative Maximum STEM Price is applied when gas fired generation is fully committed and liquid fuelled generation is required.

The prices that currently apply are shown below in Table 1. Further details are also available on the AEMO website: http://wa.aemo.com.au/home/electricity/market-information/price-limits.

Table 1 Maximum Prices in the WEM

Variable	Value	From	To
Maximum STEM price	$253.00 / MWh	1 July 2015	1 July 2016
Alternative Maximum STEM Price	$315.00 / MWh	1 Jun 2016	1 Jul 2016

Note that the Alternative Maximum STEM Price is adjusted monthly according to changes in the three-monthly average Perth Terminal Gate Price for distillate (less excise and GST)[5].

1.2 Engagement of Jacobs

Jacobs was engaged by AEMO to assist it in:

- reviewing the appropriateness of the Maximum STEM Price and the Alternative Maximum STEM Price, as required under clause 6.20.6 of the Market Rules; and
- proposing values for the Maximum STEM Price and Alternative Maximum STEM Price to apply for the year commencing 1 July 2016.

This Final 2016 Report was derived from the Final Draft 2016 Report, after the public consultation process, and will be submitted by AEMO to the Economic Regulation Authority (ERA) for approval under clause 2.26 of the Market Rules.

1.3 Basis for review

The basis for the review of Maximum STEM prices is set out in the Market Rules as shown in Appendix A. The key elements of the process are to:

- review the cost basis for the Maximum STEM Price and the Alternative Maximum STEM Price;
- prepare a draft report for public consultation; and
- finalise the report based upon the public consultation.

The Market Rules specify a methodology in clause 6.20.7(b) related to the costs of a 40 MW gas turbine generator without specifying the type of gas turbine technology – for example aero-derivative or industrial gas turbine. The key factor is that the costs should represent the short run marginal cost of “highest cost generating works in the South West Interconnected System (SWIS)”. The aero-derivative turbines are more flexible in operation, have lower starting costs and generally have higher thermal efficiency. The aero-derivative turbines better serve a load following regime and very short peaking duty. The industrial gas turbines are not as well suited to extreme peaking operation and therefore would be expected to be the last units loaded for this purpose, if they were not already running for higher load duty.

[5] The Market Rules require AEMO to use the 0.5% sulphur Gas Oil price as quoted in Singapore, or another suitable price as determined by AEMO.

The analysis in this report calculates the Energy Price Limits for selected actual industrial gas turbines and aero-derivative turbines and selects the highest cost unit as the reference unit.

The formula for calculating the Energy Price Limits is stated as:

(1 + Risk Margin) x (Variable O&M + (Heat Rate x Fuel Cost))/Loss Factor

Where:

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine (OCGT) generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW OCGT generating station expressed in $/MWh, and includes, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW OCGT generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW OCGT generating station, expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW OCGT generating station relative to the Reference Node.

AEMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

1.3.1 Analysis in this report

The methodology outlined in clause 6.20.7(b) makes explicit allowance for the fact that the applicable costs that make up the estimated SRMC of the highest cost generating works are difficult to estimate. There is no single value for all operating conditions. The Maximum STEM Price, being fixed, must be set so that it provides sufficient incentive for peaking plants to provide energy to the STEM and the Balancing Market in the presence of highly variable market conditions.

In the equation in clause 6.20.7(b) Variable O&M, Heat Rate, Fuel Cost and Loss Factor are all deterministic values for which an average value can be provided; the uncertainty in the calculation of an appropriate Maximum STEM Price or Alternative Maximum STEM Price is intended to be dealt with through the concept of the Risk Margin.

The analysis in this report seeks to apply industry best practice to establish an appropriate Risk Margin.

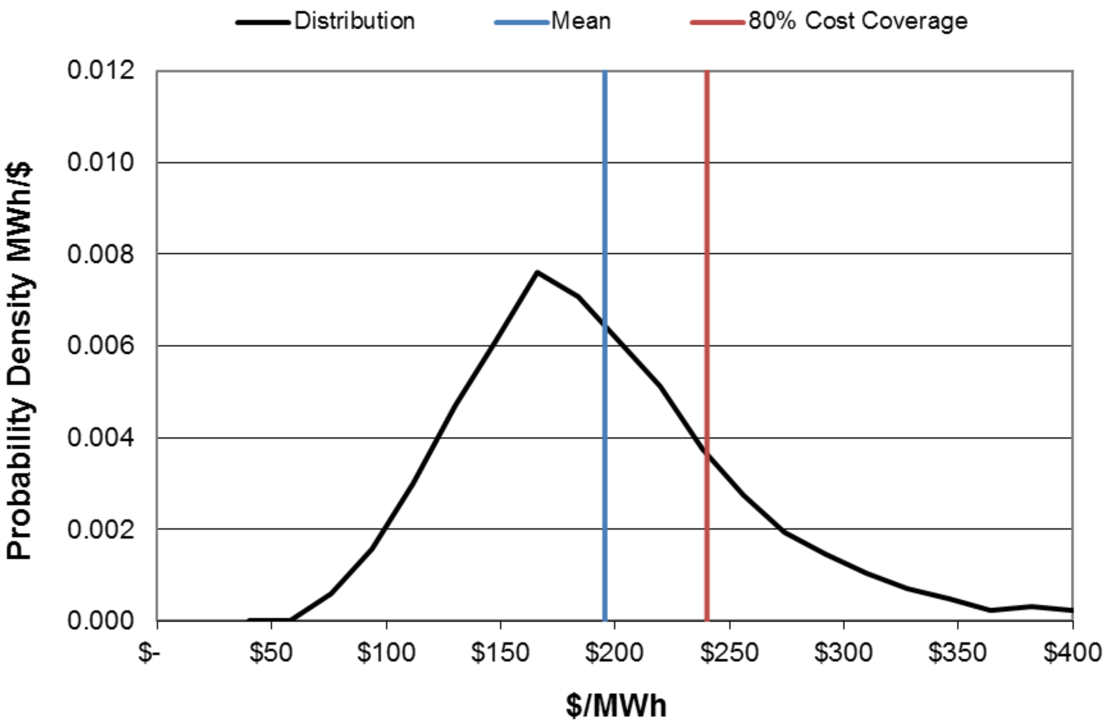
The approach taken to calculate the Risk Margin in this report (as with previous years) is to identify the likely variability in key inputs to the calculation of Energy Price Limits and model the impact that the variability in the key inputs would have on the Dispatch Cycle cost. This method results in a probability distribution of possible costs from which the recommended price limit is selected to cover 80% of the possible outcomes (representing a 20% probability that the price may be exceeded). The Risk Margin is then the percentage difference between the cost outcome that covers 80% of possible outcomes and the cost derived from the mean inputs according to the formula in clause 6.20.7(b).

This is provided diagrammatically in Figure 1 for the operating cost of the Pinjar gas turbines and based on the historical dispatch pattern of Pinjar from January 2014 to December 2015 inclusive. The charts show the density distribution as a black line, the product of the mean of the formulae inputs as the blue vertical line, and the value exceeded 20% of the time as the red line, which are the proposed Maximum STEM Prices in this instance.

Jacobs notes the probability curve used to calculate the Risk Margin is a subset of all of the possible Dispatch Cycle cost outcomes. That is, the Risk Margin is based on the 80th percentile outcome for the generation described by clause 6.20.7(b) and does not represent all of the generation that participates in the STEM. It only considers Dispatch Cycles of between 0.5 and 6 hours duration.

Jacobs believes this approach most appropriately reflects the intent of setting Energy Price Limits for extreme peaking operation and the concept of the Risk Margin as detailed in clause 6.20.7(b).

Figure 1 Probability density for price cap calculation for highest cost generator



Further, Jacobs also notes that in using this methodology to calculate the Risk Margin, the relevant Energy Price Limits are calculated before the Risk Margin. This makes the concept of the Risk Margin an output of the calculation methodology rather than an input determining the Energy Price Limits.

1.4 Issues considered in the review

In the course of this price cap review, the following issues concerning the methodology have been identified. Issues identified and addressed in previous years' reports have not been detailed in this report.

1.4.1 Review of operating and maintenance costs of aero-derivative and industrial gas turbines

The last detailed review of operating and maintenance costs of the Pinjar and Parkeston units was carried out in last year's review. A high level review of the current market was conducted for this year's study and it was concluded that it is appropriate to adjust last year's costs for movements in forex and to also escalate costs by CPI.

1.4.2 Dispatch characteristics of gas turbines

An analysis of Pinjar dispatch shows that the frequency of unit starts had been steadily decreasing over the last four years. This trend has now ceased, or has at least paused, as frequency of unit starts as well as dispatch levels in 2015 are similar to the 2014 values. The most plausible explanatory factor previously put forward for this dynamic was the commissioning and ongoing operation of the high efficiency gas turbines (HEGTs) at Kwinana. The HEGTs at Kwinana have a lower SRMC relative to Pinjar and therefore the impact of their commissioning on the dispatch of Pinjar will be ongoing.

Last year's approach was to capture this change by only including dispatch data from the 2013 and 2014 calendar years to determine the characteristics of the distribution of a typical Dispatch Cycle. Given that the Dispatch Cycle has now settled down over the last two calendar years, in this year's review we have decided to use only historical data from calendar years 2014 and 2015 to determine the Dispatch Cycle of the plant. The change in start frequency and energy dispatched per cycle has been reflected in the representation of Pinjar operation for the 2016/17 financial year, as detailed in section 3.3.1.

1.4.3 Changes in methodology for determining spot gas distribution

In last year's review we changed the methodology used from the previous year for forecasting the spot gas price distribution. The reasons for doing this are illustrated in Figure 2, which shows a large disparity between the 2014/15 forecast price distribution and the actual 2014/15 monthly maximum spot price distribution, which is considered to be the most relevant price distribution for this analysis. Figure 3 also shows the actual year to date and projected 2015/16 maximum monthly gas price distributions. There is substantial overlap between the forecast and actual price distributions, and as one would expect, more uncertainty in the forecast distribution. This overlap demonstrates the efficacy of the revised forecast gas price methodology.

Figure 2 Forecast and actual maximum monthly spot gas price distributions for FY2014/15

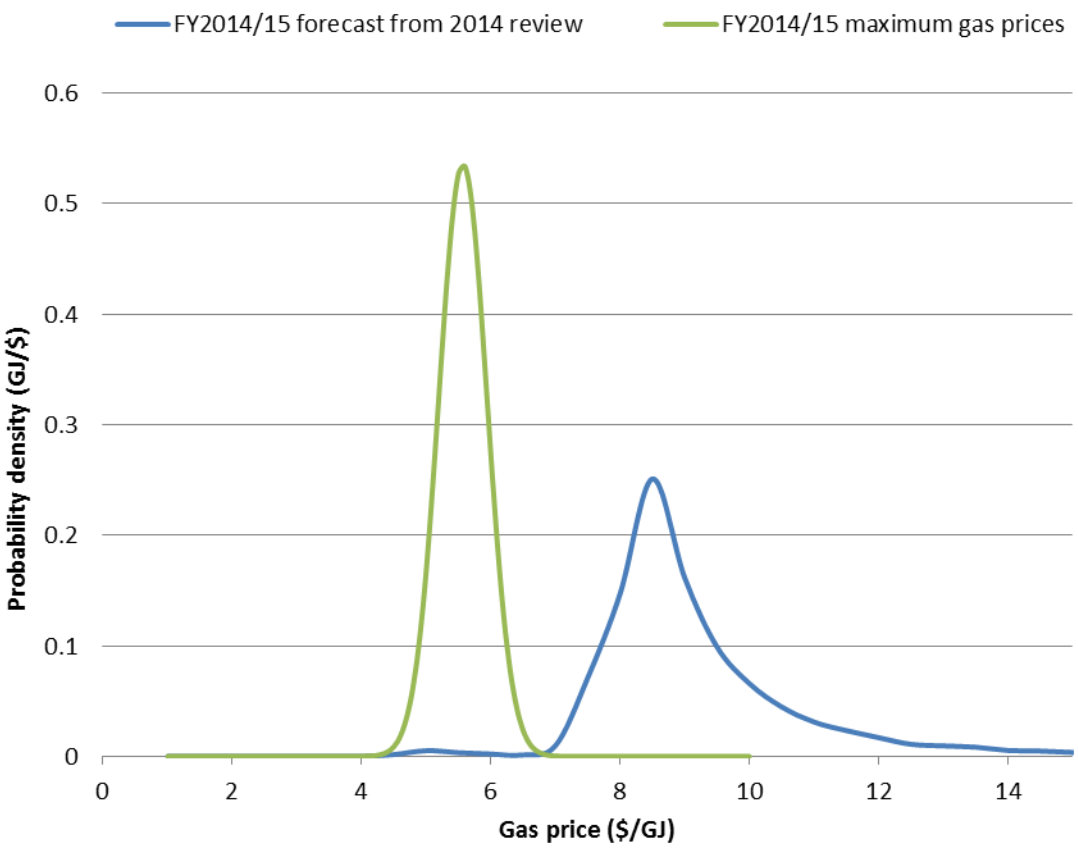
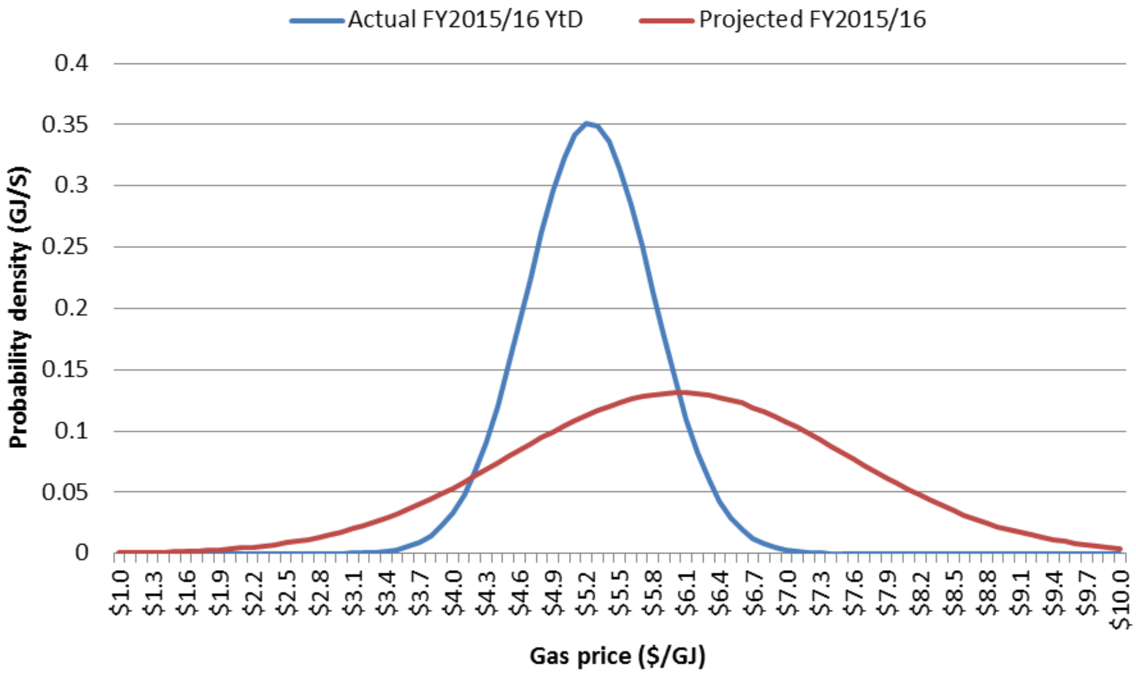


Figure 3 Forecast and actual maximum monthly spot gas price distributions for FY2015/16



In last year's analysis we ultimately adopted a dual approach for forecasting the spot gas price distribution. Both methods used time series analysis to forecast the price distribution. This was deemed to be appropriate since the method places greater weight on the most recent movements in the gas price, which are the most relevant in forecasting gas prices over the next 12 months. The first approach was to use the average monthly gas price distribution on the basis that there is a weak link between the occurrence of peaking generation and the spot gas price, implying that the entire spot gas price distribution is relevant in assessing the price of gas for peaking generators. However, on further reflection we concluded that the available data was not granular enough to enable us to isolate the relationship between the gas price and peaking generation. As a result, we produced a second spot gas price forecast based on the maximum monthly spot gas price, which was more aligned with previous analysis. Our final recommendation was to base the Maximum STEM price on the second gas price distribution, which yielded higher gas prices. The reason for this was the imperative that the Maximum STEM price should not act to impede participation of high cost generators – if our gas price forecast was too low then it could violate this requirement.

In this year's review we continue in the same vein and the forecast gas price distribution has been based on maximum monthly spot gas prices.

2. Methodology

2.1 Overview

This chapter discusses the price cap methodology as it was applied in this review. Previous reports on the Energy Price Limits, particularly the 2009 review, have thoroughly discussed the evolution of these methods.

2.2 Concepts for Maximum STEM Prices

2.2.1 Basis for magnitude of price

The estimation of the Maximum STEM Price depends on the consideration of a number of factors. Since the purpose of the Maximum STEM Price is primarily to mitigate market power, there are conflicting objectives in setting the Maximum STEM Price, which should be:

- low enough to mitigate market power;
- high enough so as to ensure that new entrants are not discouraged in the peaking end of the market; and
- high enough that generators with dual fuel capability (gas and liquid) do not regularly switch to liquid fuel as a result of short term gas market prices exceeding the basis of the Maximum STEM Price.

However, it is not possible to predict the particular circumstances that would define the highest cost peak loading conditions in any particular period of time. Therefore the value that would be high enough to allow the market to operate cannot be accurately determined. A number of factors influence this calculation including plant cost and market factors. The following section discusses how this uncertainty is managed in setting the price caps.

2.2.2 Managing uncertainty

From the viewpoint of AEMO, it does not have perfect knowledge of all the possible conditions that determine the cost of generation at any particular time. Therefore some margin for uncertainty is needed when applying the expected costs to set a price limit.

The Market Rules allow for the uncertainty of the short run average cost of peaking power to be assessed and a value to be determined that results in a price cap that exceeds the majority of potential circumstances with an acceptable probability, say 80% to 90%. This range is typical of risk margins observed in electricity markets where traders cannot accurately predict future market conditions and yet must strike a fixed price for trading purposes to manage uncertainty. The margin is applied to the expected cost to ensure that the imposition of a capped price does not impede participation of high cost generators in the market under high demand or low reserve supply conditions.

In the event that future market conditions prove that the Maximum STEM Price is constraining economic operation of peaking plant, AEMO is able to review the price settings to reflect prevailing market conditions and recommend an adjustment to the probabilities. Thus the risk that generators would be financially disadvantaged by the price cap is very low.

2.2.3 Selection of the candidate OCGT for analysis

The previous analysis of Energy Price Limits has shown that the Pinjar 40 MW gas turbines (GTs) have the highest cost for short dispatch periods and the Parkeston aero-derivative gas turbines are the next most costly to run for peaking purposes. This has consistently applied since the Energy Price Limits were first determined. In the 2011 review, the Kwinana twin sets were included in the analysis and it was shown that they are very unlikely to have higher dispatch costs than the Pinjar gas turbines, and that they do not need to be considered further. There is no reason to suggest that this would change in the foreseeable future. For these reasons the Pinjar 40 MW machines and Parkeston aero-derivative gas turbines are the two candidate machines selected for analysis in this report. The determination of the highest cost machine is discussed further in section 2.4.

2.3 Determining the Risk Margin

0The methodology in this report seeks to model the uncertainty in the calculation of the Risk Margin in a manner that appropriately covers variability in the key inputs detailed in clause 6.20.7(b) of the Market Rules. These inputs are:

- Variable O&M
- Heat Rate
- Fuel Cost
- Loss Factor

The following details the methodology by which the variability in each of these inputs is determined and the process by which these parameters are combined to determine the Energy Price Limits.

Throughout this section the text in square brackets is provided to link the methodology discussion to the variables of the operational formulae in Appendix B.

2.3.1 Variable O&M

The determination of Variable O&M costs for the candidate machines is based on engineering data available to Jacobs. These values were last reviewed in detail in last year’s 2015 review. For this year’s study, an assessment of the maintenance cost has been conducted by Jacobs in the context of last year’s review. It was found that there was no material change in the maintenance regime of the relevant gas turbines and general trends in the industry remain unchanged. Overhauls are often triggered by turbine condition assessments overlayed by equivalent operating hours triggers.

Taking the above into consideration Jacobs has updated base maintenance costs using the same assumptions as in the 2015 study with a correction for forex movements since then and has also applied a standard CPI cost escalation, which is appropriate for the industry.

O&M costs are incurred in the following manner:

- Type 1: Annually whether the unit is operated or not.
- Type 2: On a per start basis independent of the time the unit operates for, or loading level. [SUC]
- Type 3: On a per hour of operation independent of machine loading. [VHC]
- Type 4: On a per MWh basis (variable basis).

Type 1 costs above are not included in the Energy Price Limit determination as they are not considered short run costs. It is expected that such costs would be captured in the Capacity Credit payment mechanism within the market for fixed operating costs.

Types 2 through 4 above must be stated on a per MWh basis to meet the requirements of clause 6.20.7(b) of the Market Rules. As a result Types 2 and 3 require conversion to a per MWh basis. This conversion is achieved by estimating how much generation is associated with each start (Type 2) or hour of operation (Type 3) as applicable. These items are dependent on the duration for which the machine is operational and how heavily loaded the machine is while it is being dispatched. These components change dramatically from machine to machine and are a key source of uncertainty in the development of the Variable O&M. To determine these items Jacobs uses the concept of the Dispatch Cycle.

As in previous years, the characteristics of Dispatch Cycles experienced by the Pinjar and Parkeston machines were determined through the analysis of historic dispatch data obtained from AEMO. This sampled dispatch data is expressed through the following variables:

- The sampled number of starts per year. [SPY]
- The sampled run time between 0.5 and 6 hours. [RH]

- The sampled Dispatch Cycle capacity factor as a function of run time. [CF]
- The sampled maximum capacity. [CAP]

The latter three variables are multiplied to determine the MWh delivered per start [MPR] which divides the start-up operating cost to give the variable O&M. This is shown in detail in Appendix B.

The number of starts per year for Pinjar and Parkeston are based on analysis of historical data from January 2014 to December 2015. It was deemed that including only data from the last two years was an appropriate approach as this best captures the impact of the ongoing operation of HEGTs in the SWIS, which may be having an impact on the dispatch patterns of these peaking generators. The analysis of the recent dispatch patterns of these units is summarised in section 3.3.1.

2.3.2 Heat rate

The heat rate of the reference machines is based on data provided by the manufacturer as available in heat rate modelling software GT Pro. The heat rate characteristics for run-up and for continuous operation were reviewed and refined in the 2012 review. This data was again reviewed in last year's study but remains unchanged as it is identical to the information used in the 2012 review. The manufacturer data reflects that the actual heat rate of the machine varies with the following:

- Machine load
- Temperature
- Humidity
- Atmospheric pressure.

For the purpose of this report, heat rates are considered with atmospheric pressure defined at 15 m above sea level and over the range between two conditions:

- temperature of 41°C, humidity 30%
- temperature of 15°C, humidity 60%

The peaking dispatch of the reference machines occurs throughout the year, and therefore the variation of heat rates attributable to temperature variation has been added to the underlying uncertainty. This underlying uncertainty is modelled as having a deviation of 3%[6]. The mean heat rates were interpolated between the above reference temperature values for 25°C corresponding to the mean daily maximum temperature in Perth.

The Market Rules state that the Heat Rate should be determined at "minimum capacity". The concept of minimum capacity itself has a range of associated uncertainties. From an engineering perspective a machine can for short periods be run to almost zero load. However, the associated heat rate and increased maintenance burden make this unsustainable over extended durations. Thus, to identify the appropriate minimum capacity reference Jacobs reviewed historic machine operation to determine an appropriate minimum load for the reference machines. A heat rate was then extracted from the manufacturer's data for that loading level, as well as the sensitivity of the average heat rate to the variation in output, for modelling the uncertainty in the minimum capacity level. [AHRM]

In addition to the above, the Pinjar machine uses material quantities of fuel during the start-up process that must be considered in the analysis. The start-up fuel is added to the total cost and included as part of the Fuel Cost term. Through this process the start-up fuel cost is converted from a fixed fuel consumption to a per MWh consumption using the Dispatch Cycle concept discussed in section 2.3.1 above. [SUFC]

The "heat rate at minimum capacity approach" is cross checked against a second methodology that establishes the heat rate of the Pinjar machine across the Dispatch Cycle of the machine and then calculates the aggregate fuel consumption to determine an average heat rate. This approach includes the fuel consumed in start-up and

[6] 3% of the heat rate at 25°C obtained by interpolating with the values at 41°C and 15°C.

the modelled heat rate for the various load levels as the machine moves through the Dispatch Cycle, from start-up to shut-down. This approach is undertaken with reference to the Dispatch Cycle method discussed further in section 4.5.1 of this report. This method is not used to determine the recommended Energy Price Limits. Rather, it is used to confirm that the Market Rules can provide Energy Price Limits that reflect the observed pattern of dispatch, and consequently the appropriate heat rate levels.

2.3.3 Fuel cost

This report considers a modelled distribution of likely gas prices to determine the Maximum STEM Price.

Gas cost

The modelling of gas cost is based on additional analysis undertaken by Jacobs and summarised in Appendix C. Jacobs has used an ARIMA time series model for forecasting the gas price this year, which is based on historical maximum monthly gas prices. The resulting forecast distribution is normal, and its mean and standard deviation were derived from the output of the ARIMA forecast. The variance of the distribution was greater than that of last year's distribution, reflecting greater expected uncertainty around future spot gas price movements.

Of critical importance to the setting of the Maximum STEM Price is the definition of the upper bounds of this distribution. In this report the upper bound of this distribution is defined by the gas cost that would give the same Dispatch Cycle cost as if distillate were used. This is because it is considered unlikely that the spot gas price would exceed the value of gas in displacing distillate usage in OCGTs. This situation reflects the significant capacity for dual fuelled gas turbines in the SWIS, including Pinjar. In defining this upper bound, a position must be taken on the delivered price of distillate and the quantity of distillate required to deliver the same energy as a unit of gas. The latter item is dependent on the generation technology adopted (industrial machines versus aero-derivatives) when comparing the results to determine the highest cost OCGT. [VFC] and [FSR]

Transport cost

The gas transport costs are based on analysis undertaken by Jacobs. These costs have been generally modelled as variable costs [VFTC]. However, for the Parkeston machines, parts of the costs have been treated as fixed costs [FT]. The spot gas transport cost distribution for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) has decreased slightly from the 2014 review due to 2015 CPI tracking lower than 2.5% (see section C.7.1.1).

Daily load factor

The impact of variation in daily forecast volume error is modelled through the inclusion of a daily gas load factor [VFTCF]. This daily gas load factor is applied to the fixed transport cost [FT] and the gas cost [VFC].

2.3.4 Loss factor

The loss factor is extracted from the published loss factors for the candidate OCGTs. As this is a published figure no variability is modelled for this input; that is a single data point is used. [LF]

2.3.5 Determining the impact of input cost variability on the Energy Price Limit

For each candidate machine and for each of the variables detailed above a range and a distribution are applied from one of the following options:

- Assume the variable is normally distributed and assign a standard deviation with the base value representing the mean, and then apply maximum and minimum limits if appropriate.
- When specific information is available from the WEM or other sources, Jacobs has analysed the information and derived a suitable probability distribution to represent the uncertainty. This method has been used to analyse run times, generation available capacity and generation capacity factors related to the Dispatch Cycle.

For each candidate machine, these distributions are used to develop a set of 10,000 input combinations to the equation detailed in Appendix B[7]. Based on the distribution of the inputs, this equation is processed for each of this set of inputs to provide a profile of possible costs determining the Energy Price Limits. From this profile a potential Energy Price Limit is selected that covers 80% of the outcomes for that generator.

2.3.6 Risk Margin

To determine the Risk Margin associated with the Energy Price Limit the following process is adopted. The mean values of the relevant probability distributions described above are used to calculate the term

(Variable O&M + (Heat Rate x Fuel Cost))/Loss Factor

in clause 6.20.7(b) from which the Risk Margin is determined to match the Energy Price Limit. Hence the Risk Margin is calculated as:

$$\text{Risk Margin} = \frac{\text{Energy Price Limit as determined in section 2.3.5}}{\text{(Variable O\&M + (Heat Rate x Fuel Cost))/Loss Factor}} - 1.0$$

This method respects the construction of the Energy Price Limits as currently defined in the Market Rules whilst providing for an objective method for defining the Risk Margin having regard to an analytical construction of the market risk as perceived by AEMO using public data.

Jacobs notes that the start-up fuel consumption [SUFC] is included in the Heat Rate input. That is the heat rate for the purposes of clause 6.20.7 (b) includes both the steady state heat rate at minimum capacity [AHRM] and a component that covers the start-up fuel consumption [SUFC]. In previous reviews, the option of presenting the start-up fuel cost in the Variable O&M input was considered; however Jacobs felt as this component was part of the fuel consumption of the machine it was best presented in the heat rate.

2.4 Determination of the highest cost OCGT

Based on the analysis above for Parkeston and Pinjar the unit with the highest Maximum STEM Price is selected. As in previous years the model Pinjar units have been identified as the highest cost machines. To simplify the report the calculations for Pinjar are presented in Chapter 3. The corresponding analysis for Parkeston is provided in Appendix D.

2.5 Alternative Maximum STEM Price

Although the Alternative Maximum STEM Price is calculated consistent with the requirements of clause 6.20.7(b) detailed above it is recalculated monthly based on changes in the monthly distillate price. This defines the delivery of the Alternative Maximum STEM Price in this report as a function of distillate price in Australian dollars per GJ, ex terminal. It also removes uncertainty in the cost of distillate from consideration in determining the Risk Margin discussed above. In the 2014 and 2015 reviews, the road freight cost was not included in the variable fuel component of the Alternative Maximum STEM Price as this freight cost was considered to be relatively constant over a one year period. This change remains appropriate for the current review as the freight cost is still considered to be constant over one year.

The Lower Heating Value heat rates for industrial gas turbines and aero-derivative machines are increased by 5% for the calculation of the Alternative Maximum STEM Price to represent the operating conditions when fired on distillate. When adjusted for the ratio of lower to Higher Heating Value on the two fuels, the effective increase in Higher Heating Value is 0.27%. This factor was also applied to the start-up fuel consumption.

[7] Previous years' analysis has been based on 1,000 Monte Carlo samples. We increased it to 10,000 samples this year because the relatively low number of samples previously used was the source of some lumpiness in the output distributions. As a result output distributions are noticeably smoother in this year's analysis.

The Risk Margin for the Alternative Maximum STEM Price is determined by calculating the Dispatch Cycle cost that is exceeded in 80% of Dispatch Cycles of less than 6 hours for a fixed distillate price. This enables an equation to be determined with a fuel independent (“non-fuel”) component plus a “fuel” cost component that is proportional to the Net Ex Terminal distillate price. This is presented in section 4.2.

The method for the selection of the non-fuel and the fuel cost factor in the formula for the Alternative Maximum STEM Price was based upon 10,000 samples of each of the two cost factors combined with a range of fixed distillate prices between $6/GJ and $36/GJ, to assess the 80% probability level of cost for each fuel price. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. This function is shown with the results in Figure 10. This method ensures that the resulting cost is at the 80% probability level over this fuel cost range, given the cost and dispatch related uncertainties.

The elements which make up the non-fuel cost components for the Alternative Maximum STEM Price are shown in Appendix B.

3. Determination of key parameters

This chapter discusses the analysis of the various cost elements and how they are proposed to be used to set the Energy Price Limits using their probability distributions and mean values. This section is structured to follow the cost elements as defined in clause 6.20.7(b) of the Market Rules. A summary of the operational distributions of the input variables is provided in Appendix B. More detailed information on gas prices is provided in Appendix C. Other probability distributions are described in a confidential Appendix provided to AEMO and ERA. The calculations for the aero-derivatives are presented in summary form in Appendix D.

3.1 Fuel prices

3.1.1 Gas prices

The analysis of gas prices has been based on the aforementioned additional Jacobs analysis. The recommended approach was to set gas price and transport cost on projected spot gas trading from 1 July 2016. The value of gas will be based on the opportunities in the spot gas market for gas that would be used by a 40 MW peaking plant at Pinjar.

3.1.2 Price of gas

The price of gas delivered to a 40 MW power station has two components, the price at the gas producer's plant gate and the cost of transmission from the plant gate to the delivery point at the power station. In this study the gas price has been estimated on the basis that the gas is sourced from the Carnarvon Basin and transported to generators in the South West via the DBNGP.

The spot market gas price, which excludes the transport component, has been based upon alternative uses, either in:

- displacing contracted gas which is not subject to take-or-pay inflexibility,
- changes in industrial processes, or
- displacing liquid fuel in power generation or mineral processing.

These alternative uses have a range of values and Jacobs has assessed a range from \$2.70/GJ to \$7.50/GJ as representing 80% of the range of uncertainty for the gas price forecast.

A time series forecasting approach was used to derive this distribution, which was based on the maximum monthly spot gas price. This was the same approach used in last year's modelling, but an additional adjustment was applied in this year's analysis to account for the unusually low spot gas prices and to reflect the recent upwards trend in the gas contract price which also has an influence on the spot price. Jacobs further explored factors influencing the spot gas price and a reasonably strong correlation (with a correlation coefficient of 0.57) was found to exist between the Brent crude oil price denominated in US dollars and the historical maximum monthly spot gas prices in WA. With the expectation that the recent upwards trend in the Brent crude oil price will continue in the short to medium term, Jacobs considered it reasonable to add an uptrend to the maximum monthly spot gas price forecast to represent the expected movements in the oil price.

Jacobs has applied a pass through of 50% of the expected movement in the contract gas price[8] through to the maximum monthly spot gas price. The limitation to 50% is due to the imperfect correlation between the Brent crude oil price and the maximum monthly spot gas price and also not to pass through other factors influencing contract prices that do not necessarily impact on spot gas prices. The expected increase in the 2017 contract gas price relative to the 2016 price is \$0.92/GJ. Jacobs therefore added \$0.46/GJ to the mean of the projected spot gas price distribution and has kept the same standard deviation. Gas prices are therefore represented as a normal distribution with a mean of \$5.54/GJ and a standard deviation of \$1.77/GJ.

[8] IMO, *Gas Statement of Opportunities*, Nov 2015, p.90.

A more detailed description of the methodology and assumptions underpinning the gas price forecast is discussed in Appendix C.

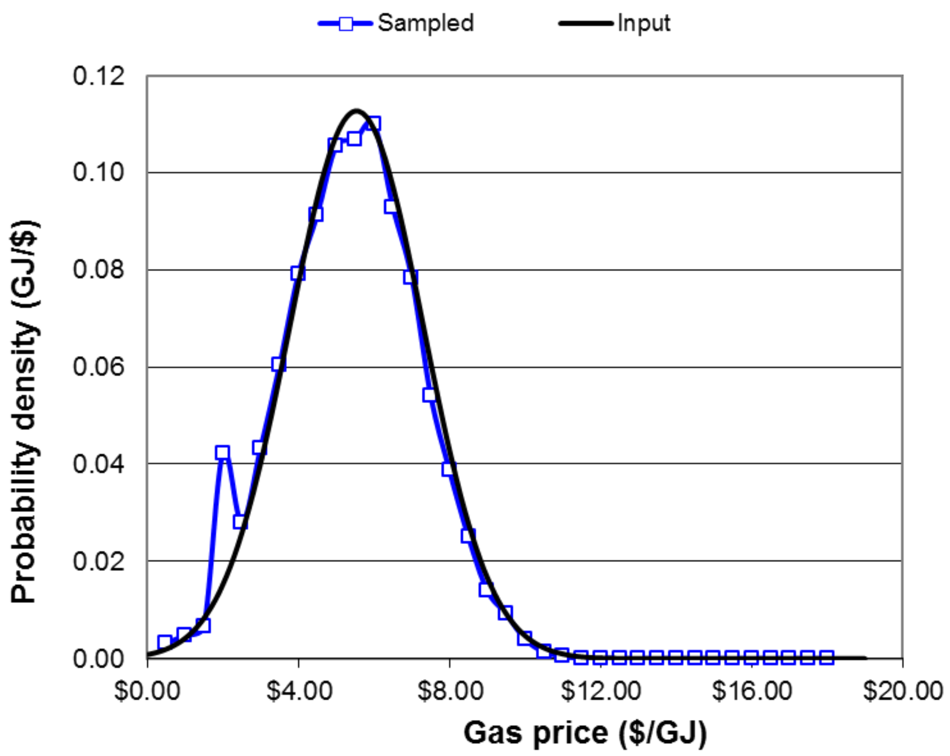
As described in section 2.3.3 above, a gas price range up to $19.6/GJ has been modelled with the gas price capped by the comparative value relative to the distillate price[9]. Jacobs has calculated a breakeven gas price[10] for each of the 10,000 simulated Dispatch Cycles given its particular characteristics, including a cost penalty for liquid firing where applicable for industrial gas turbines[11]. The breakeven price was estimated to equalise the Dispatch Cycle average energy cost. This is preferable to capping the gas price distribution at a single level when estimating the Energy Price Limits.

Jacobs has chosen to represent the gas price as a normal distribution up to $19.6/GJ, as shown in Figure C- 4 in Appendix C. A normal distribution was the appropriate choice as it represents the error distribution associated with the ARIMA forecast. The final normal distribution used had a mean of $5.54/GJ and a standard deviation of $1.77/GJ.

The resulting gas price distribution as sampled is as shown in Figure 4. The smooth black line represents the density function of the normal distribution for the gas price from which 10,000 samples were drawn. Some small distortions are evident in the sampled data compared to the input distribution. These are the effect of the distillate price serving as a cap on the gas price.

The sampled gas price did not exceed $12.50/GJ for the industrial gas turbine once capped by the breakeven gas price. Thus modelling the gas price initially to $19.6/GJ was sufficient. The maximum delivered gas price was $15.43/GJ to the industrial gas turbines.

Figure 4 Gas price distribution as modelled with upper price limited to the distillate equivalent



[9] The distillate price cap is discussed further in section 3.1.6 of this report.

[10] Note that in this year's modelling the breakeven price, if left unaltered, could be negative due to the very large standard deviation of the distillate price distribution. Jacobs put a floor of $2/GJ on the breakeven price of gas, based on the minimum spot gas price observed over the last seven years. Note that the resulting Maximum STEM Price was not sensitive to the level at which the price floor was set, and as a result this method was considered to be an appropriate way of dealing with the issue.

[11] No liquid firing operating cost penalty was applicable to aero-derivative gas turbines which are designed to use liquid fuel.

3.1.3 Daily load factor

Consistent with the approach adopted for last year's review, it has been assumed that, when applied to spot trading on a daily basis, the daily gas load factor is only important to the extent that it represents daily forecast volume error. For that purpose, it is modelled as having an 80% confidence range between 80% and 98% with a 95% most likely value (the mode). The continuous distribution had a mean of 97.0%, but when the maximum value of 1.0 was used to truncate the distribution, the mean value was 89.91%. Jacobs developed the lognormal distribution of Spot Gas Daily Load Factor shown in Figure C- 6. The distribution was truncated and redistributed so that there was no discrete probability of a value of 100%. This was in accordance with the methodology applied in last year's review. There is a 0.005% probability of a value at the minimum value 60%.

The effective spot price was calculated by dividing the spot price sampled from the capped distribution in Figure C- 4 by the daily load factor sampled from the capped distribution in Figure C- 6.

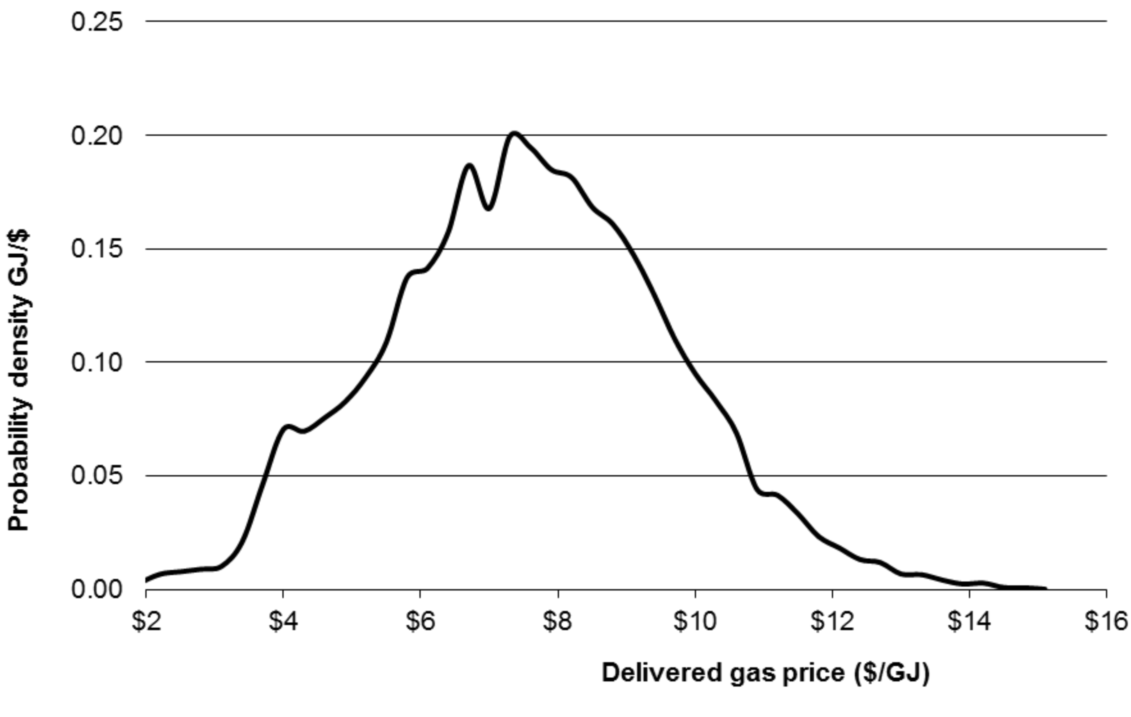
3.1.4 Transmission charges

In previous reviews, ACIL Tasman has recommended basing the gas transport cost on spot market conditions. This same approach was adopted for the last two reviews and for this year's review. For the transport to Perth, a lognormal distribution is recommended with the 80% confidence range being between $1.46/GJ and $2.15/GJ with a most likely value (mode) of $1.736/GJ. The mean value of the transmission charge is $1.796/GJ. Jacobs developed the distribution shown in Figure C- 5 in Appendix C to represent this uncertainty in the gas transport cost. The gas cost range was taken between $1/GJ and $3/GJ which is consistent with previous reviews.

3.1.5 Distribution of delivered gas price

The composite of the variation in the gas supply price, the gas transport price and the daily load factor applied to the gas commodity price results in the probability density for delivered gas price shown in Figure 5. The effect of this skewed distribution is to spread the effect of the capped prices and to result in a range of sampled prices as shown in Table 2 for the gas price forecast.

Figure 5 Sampled probability density of delivered gas price to Pinjar for peaking purposes



The modelled delivered gas price for the Perth region had an 80% confidence range of $4.80/GJ to $10.25/GJ with a mode of $7.30/GJ and a mean of $7.57/GJ.

Table 2 Modelled delivered base gas price distribution to Pinjar

Delivered Gas Prices as Modelled	
	Pinjar
Min	$1.70
5%	$4.12
10%	$4.80
50%	$7.57
Mean	$7.57
Mode	$7.30
80%	$9.32
90%	$10.25
95%	$11.05
Max	$15.43

3.1.6 Distillate prices

The Market Rules provide for a monthly re-calculation of the Alternative Maximum STEM Price based on assessment of changes in the Singapore Gas Oil price (0.5% sulphur) or another suitable published price as determined by AEMO[12]. Therefore in this analysis a reference distillate price is assessed to define a benchmark Alternative Maximum STEM Price component that depends on the underlying distillate price.

For this purpose, the uncertainty in the distillate price is not important because the Alternative Maximum STEM Price is updated monthly. However, in modelling the gas price for the Maximum STEM Price, the uncertainty and level of the distillate price is relevant to the extent that it is used to cap the extreme spot gas prices at the level where the Dispatch Cycle cost would be equal for gas and for distillate firing for the nominated gas turbine technology and location, Pinjar in this case. The following discussion describes the expected level and uncertainty in distillate price for capping the gas price.

After enjoying a long period of relative stability from 2011 to June 2014, crude prices fell through the second half of 2014. The collapse in crude prices globally is a result of the continuing investment in non-conventional crude production, in particular the shale oil production in the US. Crude inventories continued to build through 2014 and when, in November, OPEC decided not to make any reduction to their production levels, prices broke through the $US80/bbl support level and finished the year at under $US60/bbl.

Crude prices have continued to decline through 2015 although not as dramatically as the second half of 2014. After a rally from $US50/bbl in January to $US66/bbl in May, prices dropped to $US39/bbl in December 2015 and further to $US32/bbl in January 2016. OPEC have remained silent on any curtailment of production although Saudi Arabia and Russia have recently agreed to freeze production levels. While this does not reduce the overproduction of oil, it does signal that producing countries are beginning to work together to resolve the oversupply. A consequential rally in prices occurred in February, with prices averaging $US33.5/bbl.

One of the causes of the oversupply in crude was the shale oil production increases in the US over the past five years. However, an indication of the reduction in US drilling activity is highlighted by the reduction of active drilling rigs from 2000 in January 2015 to 500 in early 2016. In addition, a number of companies (e.g. Shell, Chevron and Conoco Phillips) have announced reductions in the investment in new crude production. Whilst the

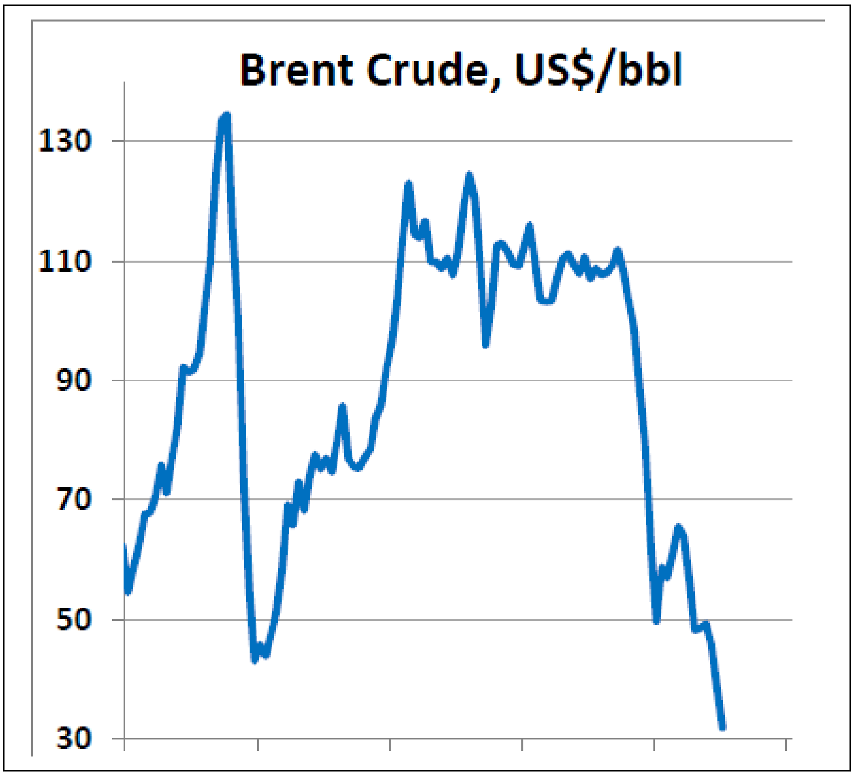
[12] For the last two years, AEMO has used the Perth Terminal Gate Price (net of GST and excise) for this purpose, as the Singapore Gas Oil price (0.5% sulphur) is no longer widely used. Moreover, the Perth Terminal Gate Price includes shipping costs and so takes into account variations in these costs due to factors such as exchange rate changes.

slowing of new production will assist in the supply and demand balances, there is currently a significant overhang of crude inventories globally which will dampen any price recovery in the short term.

There are a number of OPEC countries that are critically dependent on higher prices. A number of countries such as Venezuela and Nigeria are facing significant economic challenges while oil and gas provided 70% of Russia's export revenues when oil was over $US100/bbl. It is anticipated that these countries will be lobbying other producing countries for more oil production discipline.

In the latest Short Term Outlook released in February 2016, the EIA has assessed that global oil inventories are expected to continue to build in 2016, keeping downward pressure on oil prices resulting in an average forecast Brent crude oil price of $US37.5/bbl in 2016. On a positive note, US oil production is estimated to decrease from 9.4 to 8.7 million barrels per day. This reduction in production is likely to occur in other countries, particularly those with more recent (more costly) production facilities. The EIA is predicting a recovery of crude prices in 2017 with prices forecast to average $US50/bbl.

Figure 6 Brent Crude price: 2007 to end of 2015



Based on the above, the Brent price expectations during the subject period are estimated to be approximately $US45/bbl. As in past forecasts, this is based on the assumption that there are no significant geopolitical issues throughout the subject period.

The monthly average spot price for Singapore Gasoil (another term for diesel), which meets the Australian 10ppm sulphur specifications has tracked the fall in crude prices very closely through 2015. Prices have dropped from $US73/bbl in the first half of 2015 to just under $US50/bbl at the end of the year. In the same period, the Gasoil/Brent spread weakened from $US14/bbl to $US9/bbl in December 2015. The additions to refinery capacity in the region and the Middle East that have occurred over the past five years will maintain the pressure on less efficient refineries to close over coming years as is evidenced in Australia. Whilst recent Gasoil/Brent spreads in 2016 have remained under $US10/bbl the gasoil/crude spread is assessed to remain in the $US10.5/bbl - $US12/bbl range.

Consequently the diesel prices in Singapore for the subject time period are assessed to average $US56.25/bbl. This forecast again assumes that there are no new significant geopolitical events during this period.

The above forecast for the Singapore 10 ppm diesel price of $US56.25/bbl translates to a wholesale price, (Ex Terminal Price), in Perth, Western Australia of 101.88 Ac/litre, (Acpl). The Australian to US dollar exchange rate of 0.74 has been used for this forecast. For the purpose of clause 6.20.7(b) of the Market Rules, this price results in a Free into Store (FIS) price of 103.353 Acpl for Pinjar and 107.808 Acpl for Parkeston power stations[13]. These volumetric costs are equivalent to $13.90/GJ and $14.95/GJ for the two power stations respectively after deducting 40.29 cents excise and GST and applying a heat value of 38.6 MJ/litre. The road freight for Pinjar and Parkeston is assumed to be 1.47 Acpl and 5.93 Acpl respectively, inclusive of GST ($0.35/GJ and $1.40/GJ net of excise and GST). Both derived costs are based on the cost of trucking distillate from the Kwinana refinery to the respective power stations.

Over the period relevant to the Maximum STEM Price the price of distillate will vary due to fluctuations in world oil prices and refining margins. Based on the recent volatility in daily Singapore gasoil prices ($US12.4/bbl[14]), the distillate price is assumed to have a standard deviation of about 20.42cpl. This translates to $5.29/GJ. This standard deviation is still considerably higher than was applied in the 2014 review ($1.36/GJ) due to the recent volatility of the crude oil price, but is lower than that of the 2015 review ($7.10/GJ).

For this review, in capping the gas price the distillate price has been modelled as a normal distribution with a standard deviation of $5.29/GJ. A mean price of $13.90/GJ has been applied in the Perth region for Pinjar. The relatively high standard deviation in the distillate price indicates that the sampling range for the price of distillate used to cap the gas price will be wider than that of the 2014 review, but not as wide as that used for last year’s review. Furthermore, the lower price of distillate will also tend to lower the cap on the gas price, implying that the impact of a lower but still relatively volatile distillate price will lower the Maximum STEM Price.

3.2 Heat rate

3.2.1 Start-up

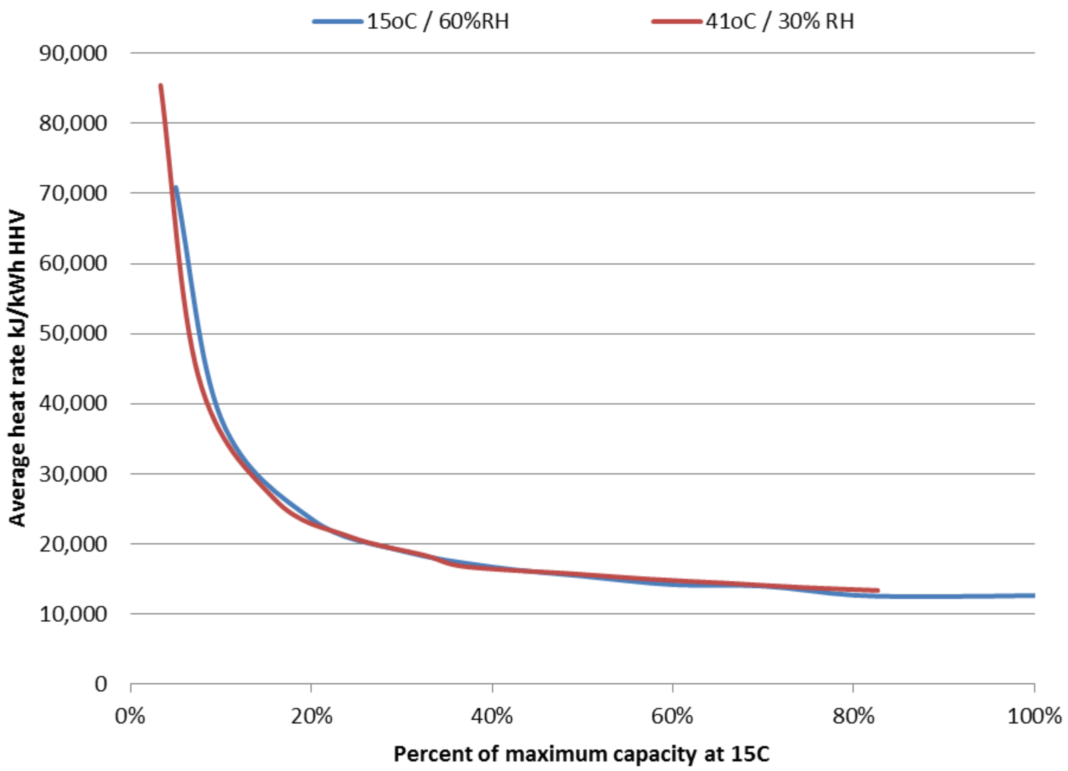
The start-up heat consumption was estimated by Jacobs as 3.50 GJ for the industrial gas turbine. An additional 5% of heat energy was allowed for start-up on distillate at Lower Heating Value which equates to 0.27% at Higher Heating Value. A 10% standard deviation was applied to these values with a normal distribution limited to 3.2 standard deviations.

Figure 7 shows the run-up heat rate curve applied for the industrial gas turbine to calculate the energy used to start the machine.

[13] Ex Terminal price is 101. 879 Acpl, which is equivalent to $0.960/litre excluding GST. After deducting excise rebate of $0.4029/litre, this results in a Net Ex Terminal price of $0.557/litre.

[14] Standard deviation of monthly gasoil prices for the period Feb 2015 to Jan 2016. In previous reviews the Brent crude monthly standard deviation had been used, however it is considered more appropriate to use the standard deviation of the Singapore gasoil price since the Singapore gasoil price is what is used to estimate the Ex Terminal price in this analysis.

Figure 7 Run-up Heat rate curve for industrial gas turbine (new and clean)



3.2.2 Variable heat rate curve for dispatch

Table 3 shows the steady state heat rates that were applied for the industrial gas turbine. They were increased by 1.5% to represent typical degradation from new conditions. The temperature sensitivity of the heat rates was estimated from the run-up heat rate curves, and was less than 1% over the range 15°C to 41°C.

Table 3 Steady state heat rates for new and clean industrial gas turbines (GJ/MWh HHV)

		% site rating			
Temp	**Humidity**	**100%**	**50%**	**33%**	**25%**
15°C	30%	12.990	15.843	18.711	21.438

The minimum load position has been extracted from the sampled data and the corresponding heat rate at minimum determined from Table 3. This heat rate at this minimum, including the temperature variability, results in a normal distribution with a mean of 18.913 GJ/MWh sent out and a standard deviation of 1.337 GJ/ MWh sent out. The mean has reduced slightly and the standard deviation has increased slightly from the 2015 review due to changes in the assessed level and uncertainty of the minimum operating level based on the analysis of actual dispatch for the Pinjar gas turbines. The change in the assessed minimum operating level changes the average heat rate modelled even though the heat rate characteristics have not been changed since the 2015 review.

3.3 Variable O&M

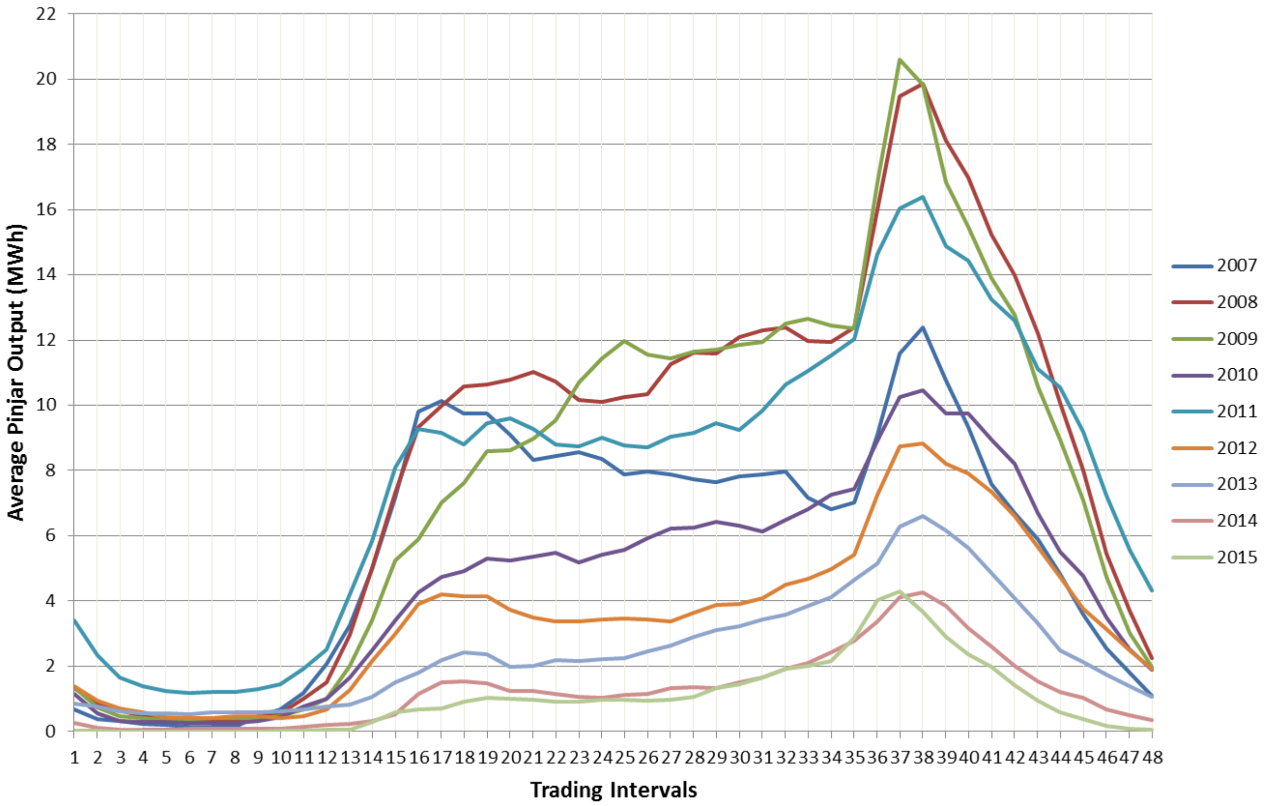
This section describes the structure of the variable O&M costs for the Pinjar gas turbines. The equivalent data for the less costly aero-derivatives is discussed in Appendix D.

The variable O&M cost for the Pinjar gas turbines in $/MWh is influenced by Type 2 and Type 3 maintenance costs discussed in section 2.3.1 above. Jacobs has not identified any significant component of operating cost which depends directly on the amount of energy dispatched. Therefore there is no specific $/MWh component other than that derived from the above costs.

3.3.1 Dispatch cycle parameters

An examination of the Pinjar dispatch data from 2007 has shown a steady decrease in both the number of starts per month over the last four years as well as the total dispatch of the plant. The daily profile of Pinjar's total output is shown below in Figure 8. This shows a distinct downtrend in Pinjar's total output from 2012 until 2014, but the trend has ceased, or at least paused, in 2015 which is very similar to 2014 output levels. In contrast Pinjar's output from 2007 until 2011 seems to vary randomly between limits.

Figure 8 Pinjar average daily generation profile (2007 – 2015)



NOTE: Trading intervals here are not based on the WEM's Trading Day. That is, trading interval 1 represents 12:00 AM to 12:30 AM, not 8:00 AM to 8:30 AM.

The change from 2012 onwards indicates a change in the role of Pinjar, and this can be traced back to the commencement and continuing operation of HEGTs in the WEM from September 2012. The HEGTs at Kwinana have a lower SRMC relative to Pinjar and therefore the impact of their commissioning on the dispatch of Pinjar will be ongoing.

The downtrend in Pinjar's dispatch has seemingly ceased, or at least paused, having remained relatively stable from the beginning of 2014 until the end of 2015. Jacobs considers that it is reasonable to assume that this stability in Pinjar's dispatch continues into the 2016/17 projection period. As such, Jacobs has discarded the 2013 Pinjar dispatch data, and has instead used all data points from January 2014 until December 2015 to determine the distribution of Pinjar's starts and the length of the Dispatch Cycle. By using two complete calendar years of data the approach avoids introduction of seasonal bias.

An analysis of the Pinjar dispatch patterns since January 2014 has shown that:

- Pinjar run times have averaged around 8 trading intervals per Dispatch Cycle. This level is lower than observed in the 2015 review (11 trading intervals). The average power generation per Dispatch Cycle has also reduced in the last 24 months when compared against the longer term average.
- Overall the incidence of short run times below 6 hours has been reducing slowly in the Pinjar dispatch since the distributions were first formulated in 2007 and in the updates for the 2009 to 2013 reviews. However, since September 2012, the incidence of short run times below 6 hours has increased. For the 2014 and 2015 calendar years, approximately 80% of all Pinjar run times were below 6 hours, compared to 70.5% in 2013 and 51.5% observed over the four year period from January 2009 until December 2012.

Number of starts per year

From the operating characteristics of the Pinjar gas turbine machines between January 2014 and December 2015, they have been required to start between 14 and 78 times per year on an individual unit basis, 52.9 starts per year on average, with average run times of between 4.0 and 4.5 hours on a unit basis. This means that the number of starts per year is the primary cost driver, rather than the operating hours.

The number of starts for the six units has a standard deviation of 24.87 starts in a period of one year. This has been represented by a normal distribution up to 3.2 standard deviations from the mean with a minimum number of starts of 10.

The parameters for the modelling of unit start frequency were:

Mean value 52.9 starts/year

Standard deviation 24.87 starts/year

Minimum value 10 starts/year

Run times

Run times are used to convert start-up costs for maintenance and fuel into an average operating cost per MWh of a Dispatch Cycle.

The run times of the peaking units have been analysed from the market data from 1 January 2014 to 31 December 2015. A probability density function has been derived which represents the variation in run times. Whilst it would be possible to set a minimum run time of say 1 or 2 trading intervals, this condition occurs infrequently, about 1 in 15 starts for the industrial gas turbines since January 2014[15]. Since other market factors have also been varied, it is preferred to assess the variation of run time as just another uncertain factor rather than treat it as a deterministic variable.

Maximum capacity

The maximum capacity of the Pinjar machines varies during the year due to temperature and humidity variation. The maximum capacity was derived from historical dispatch information taking into account the seasonal time of year using a sinusoidal fitting function. In this way, the variation of the maximum output during the year is included in the uncertainty analysis. A sinusoidal curve was used to estimate the maximum dispatch and the error around this curve was added back to give an overall distribution of maximum capacity. The applicable distributions are provided in a confidential Appendix to AEMO and the ERA.

Dispatch Cycle capacity factor versus run time

The Market Rules specify the use of the average heat rate at minimum capacity. As previously, the available loading data was analysed to assess what actual loading levels have been achieved, especially with shorter run

[15] While the aero-derivative gas turbine has higher frequency of shorter runs it should also be pointed out that it has longer average run time per start than the industrial type gas turbine. This probably reflects bilateral energy contract obligations and higher efficiency than for the industrial turbines.

times. A capacity factor for the Dispatch Cycle was defined from the historical dispatch data by the following equation:

$$\text{Capacity Factor} = \frac{\text{Energy Generated in Dispatch Cycle}}{\text{Maximum Capacity x Run Time}}$$

The capacity factor varied quite markedly even for similar run times. The relationship between these variables was defined as follows. The capacity factor has a mean equal to a linear function of the run time up to a certain threshold and then a different linear relationship above the threshold. The standard deviation of the capacity factor was assessed with the same value above and below the threshold. The details were provided in a confidential Appendix to AEMO and the ERA.

The standard deviation of the variation was 11.42% for all run times employed (i.e. up to 12 trading intervals). These values were used to formulate the capacity factor which was then clipped between the practical maximum and minimum values having regard to ramp rates and minimum stable operating capacity levels.

3.3.2 Maintenance costs

Jacobs has refreshed the maintenance costs for the 2016 review by applying appropriate forex and CPI adjustments to the costs calculated for the 2015 review (the rationale for this approach is explained in section 2.3.1). The costs are shown in Table 4 in December 2016 dollars for General Electric Frame 6 gas turbines with the maintenance stage occurring after the stated number of running hours or the stated number of starts, whichever comes first. December 2016 dollars are required in this analysis because this represents the mid-point of the 2016/17 year which is the time frame in which this analysis is applied, and the Energy Price Limits have to be expressed in nominal dollars. In the maintenance cycle there are two Type A overhauls, one of Type B and one Type C at the end. The maintenance costs were originally provided in nominal $US in February 2015. They have been converted to Australian dollars at the rate 1$AU = $US0.74, escalated from February 2015 dollars to December 2015 dollars using known historical CPI values, and then escalated to December 2016 dollars with an assumed future CPI rate of 2.0% per annum.

An overall decrease in the cost of O&M for aero-derivative turbines has been observed, based on advice from the OEM, considering the cost of the overhauls themselves and in some of the underlying assumptions regarding the cost of spare parts etc. (costs which are generally included in the cost quoted for the overhauls).

Table 4 Overhaul costs for industrial gas turbines (December 2016 dollars)

Overhaul Type	Number of hours trigger point for overhaul	Number of starts trigger point for overhaul	2016 Cost per overhaul	Number in each overhaul cycle	Cost
A	12000	600	1,461,985	2	2,923,969
B	24000	1200	4,896,599	1	4,896,599
C	48000	2400	4,242,222	1	4,242,222
Total cost per overhaul cycle					12,062,790

No adjustment is applied for any future changes in foreign exchange rates. Each maintenance cycle of 2400 units starts and ends with a Type C overhaul.

Where each generating unit has progressed in the maintenance cycle is not public knowledge. In simple terms:

- the average running hour cost is $12,062,790 / 48,000 = $251.31/hour = $6.60/MWh at full rated output (38.081 MW)[16]

[16] Calculation based on rate of output for a new machine at 15ºC, 60% relative humidity. The O&M cost is calculated based on a sampled capacity derived from market dispatch data in the Energy Price Limits cost model.

- the average start cost is $12,062,790 / 2400 = $5,026/start
- one start is equivalent to 20 running hours, but (in the G.E. methodology) they are not interchangeable, as an overhaul is indicated either by the starts criterion or the hours-run criterion, rather than a mixture of the two.

However, these costs are spread over several years and it is not appropriate to divide these costs by the number of starts or number of running hours to derive an equivalent cost accrual.

To account for the fact that the maintenance costs in Table 4 are distributed over several years and that it is not public knowledge when each unit has been maintained and where it is in its long-term maintenance cycle, Jacobs has assumed an average point in time across the maintenance cycle and that all future maintenance is spread over a remaining 20 year life.

For each cycle Jacobs has calculated a discount factor on the future maintenance cost as:

$$\frac{SPY \times (1 - (1 + DR)^{\frac{-CL}{SPY}})}{CL \times \ln(1 + DR)}$$

Where:

DR is the discount rate taken to be 9% per annum (pre-tax real);

CL is the maintenance cycle length at 2400 starts;

SPY is the average number of starts per year at 52.9; and

ln is the natural logarithm.

The formula is derived from the integral of the present value function of the future maintenance costs over the range of time from zero to CL/SPY years.

$$PV(t) = \frac{X}{(1 + DR)^t}$$

Where:

X is the maintenance expenditure at future time t with real discount rate DR; and

PV(t) is the present value of the future maintenance expenditure in year (t).

PV(t) is integrated with respect to (t) over the range 0 to CL/SPY and multiplied by SPY/CL to obtain an expected present value given that (t) is unknown and assumed to be uniformly distributed over the maintenance cycle.

Thus the total cost is:

$$X \times \frac{SPY \times (1 - (1 + DR)^{\frac{-CL}{SPY}})}{CL \times \ln(1 + DR)}$$

The scaling factor is a function of the discount rate and the average number of starts per year. A lower number of starts effectively increase the discounting of future maintenance costs per start because it has the effect of delaying the subsequent scheduled overhauls to later years.

Table 5 shows an assessment for industrial gas turbine at 52.9 starts per year. The table shows the various scheduled maintenance stages, the corresponding cost and discounted cost as well as a 20% allowance for additional unscheduled maintenance that would arise from normal peaking operations.

Table 5 Assessment at 52.9 starts/year (historical dispatch from January 2014 until December 2015)[17]

Overhaul type	Number of starts trigger point for overhaul	Cost per overhaul	Number in an overhaul cycle	Cost	Average discounted cost
A	600	$1,461,985	1	$1,461,985	$366,552
B	1200	$4,896,599	1	$4,896,599	$1,227,686
A	1800	$1,461,985	1	$1,461,985	$366,552
C	2400	$4,242,222	1	$4,242,222	$1,063,619
Discounted Cost per start		$1,260		$12,062,790	$3,024,410
Total Scheduled Cost per start		$1,260			
Unscheduled Cost Ratio		20%			
Total Cost per start		$1,512	**Based on**	**52.9**	**Starts / year**

The start-up cost at 52.9 starts per year is now $1,512/start, compared with the value of $1,678/start in the 2015 review. The decrease in discounted start cost is due to the reduction in the number of starts per year from 63.6 in the 2015 review to 52.9, which has the effect of delaying future overhauls.

For the calendar years of 2014 and 2015 the average historical MWh production per start (including Dispatch Cycles greater than 6 hours) was 64.3 MWh. The equivalent variable (non-fuel) O&M cost derived from the discounted start cost of $1,512 is $23.51/MWh compared to $19.88/MWh in the 2015 review.

In the simulation of variable O&M cost Jacobs has taken the start-up cost based on the average number of starts per year, that is with 52.9 starts per year with a standard deviation of 47.0% of that value (24.9 starts/year on an annual basis) based on the observed variability of the number of starts per year across the units.

The formulation of the capacity, run times and capacity factors is shown in Appendix B.

3.3.3 Resulting average variable O&M for less than 6 hour dispatch

For the sampled generation levels up to 6 hours based on the historical dispatch, the average variable O&M value is $57.18/MWh before the application of the loss factor. The resulting distribution which provides this mean value is shown in Figure 9.

Based on the start cost of $1,512, the average variable O&M of $57.18/MWh corresponds to an equivalent generation volume per cycle of 26.44 MWh, equivalent to about one hour running at 70% load factor or 2 to 3 hours at minimum load. It is these short Dispatch Cycles which are covered by the resulting Energy Price Limits.

Table 6 shows the characteristics of these distributions before the loss factor is applied.

[17] Values in Table 5 do not add due to rounding.

Figure 9 Probability density of variable O&M for industrial gas turbine (excluding impact of loss factor)

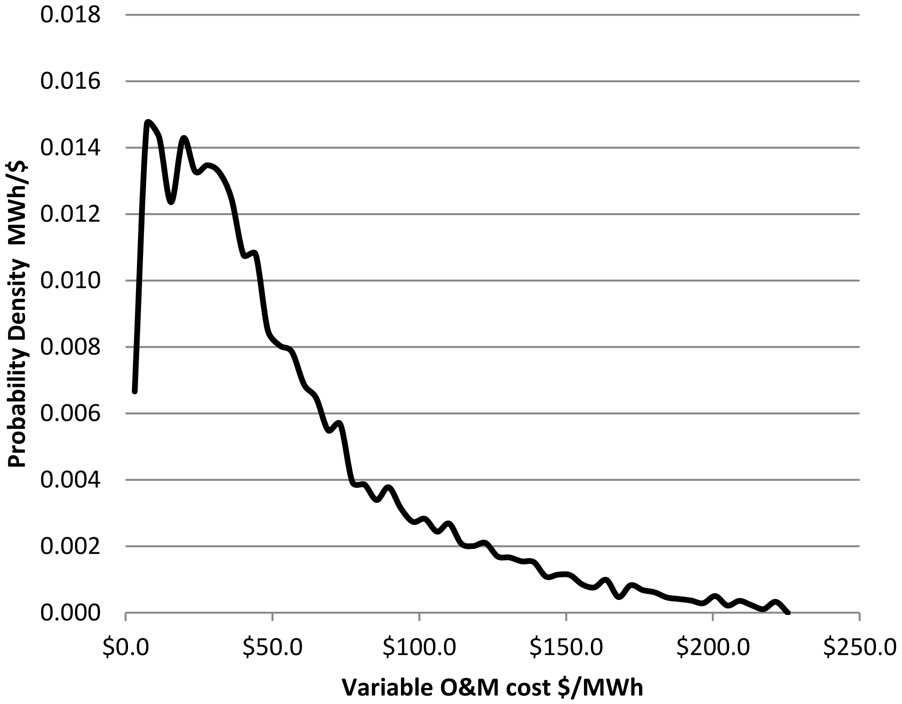


Table 6 Parameters of variable O&M cost distributions (before loss factor adjustment)

Pinjar variable O&M	$/MWh
90% POE	$10.14
Mean	$57.18
10% POE	$122.36
Minimum	$2.18
Median	$40.94
Maximum	$616.98
Standard Deviation	$55.52

The analysis detailed above for the historical dispatch results in an average variable O&M cost of $57.18/MWh with an 80% confidence range as sampled between $10.14/MWh and $122.36/MWh, excluding the impact of loss factors.

3.4 Transmission marginal loss factors

The transmission loss factors applied were as published for the 2015/16 financial year for sites where aero-derivative gas turbines and industrial gas turbines of 40 MW capacity are installed. The loss factor for Pinjar for the 2015/16 financial year is 1.0298.

The loss factors will not be available until near the beginning of the financial year, so it is expected that AEMO will need to make consequential adjustments. The loss factor for Pinjar for 2015/16 has been applied in this analysis. Parameters should be scaled directly for any change in the Pinjar loss factor published for 2016/17[18].

[18] The change in loss factor from 2014/15 to 2015/16 was -0.9% which had only a slight effect on the assessed Energy Price Limits.

Since a higher loss factor reduces the Energy Price Limits, the relationship is mathematically inverse, that is a 1% increase in the loss factor would reduce the Energy Price Limits by 1-1/(1+1%) = -0.99%.

3.5 Carbon price

Effective from 1 July 2014, the carbon price was repealed by the current Federal Government and therefore emissions from the peaking plants do not have a cost impact.

4. Results

4.1 Maximum STEM Price

The Dispatch Cycle costs of the dispatch of the industrial gas turbines are projected as shown in Table 7 using the average heat rate at minimum operating capacity and the base gas price distribution.

Table 7 Analysis of industrial gas turbine Dispatch Cycle cost using average heat rate at minimum capacity

	Pinjar Gas Turbines	
	Gas	**Distillate**
Mean	$195.60	$313.12
80% Percentile	$240.25	$403.70
90% Percentile	$278.81	$457.48
10% Percentile	$121.97	$171.16
Median	$185.42	$308.35
Maximum	$786.85	$1,039.10
Minimum	$40.65	$44.69
Standard Deviation	$68.12	$113.23
Non-fuel component $/MWh		
Mean		$61.96
80% Percentile		$84.27
Fuel component GJ/MWh		
Mean		18.546
80% Percentile		19.356
Equivalent fuel cost for % value ($/GJ)		
Mean		13.542
80% Percentile		16.503

The Maximum STEM Price is based on 80% probability that the assessed cost would not be exceeded for run time events of 6 hours or less. Using the average heat rate at the minimum capacity the Maximum STEM Price would yield a value of $240/MWh[19].

4.1.1 Coverage

It must be recognised that only short run times from 0.5 to 6 hours have been applied in formulating the distributions. This arrangement therefore covers a high proportion of Dispatch Cycles represented in the analysis, as shown in Table 8 which shows the results of a calculation which estimates the proportion of dispatch events that would be expected to be covered by the Maximum STEM Price.

Taking into account the distribution of run times, it is estimated that 83.8% of gas fired run time events would have a Dispatch Cycle cost less than the proposed Maximum STEM Price, based on the mathematical representation of uncertainties included in this analysis and using historical dispatch characteristics.

[19] In the discussion in this section, the values have been rounded to the nearest $1/MWh

Table 8 Coverage of Maximum STEM Price for Pinjar

Dispatch	Historical from Jan 2014 to Dec 2015 (80th percentile)
Proportion of Dispatch Cycles less than 6 hours	80.3%
Proportion of 6 hourly Dispatch Cycles covered by Maximum STEM Price (by simulation)	79.9%
Proportion of Dispatch Cycles covered by Maximum STEM Price	83.8%

4.2 Alternative Maximum STEM Price

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate. It is therefore necessary to separate out the cost components that depend on fuel cost and those which are independent of fuel cost. Accordingly, the lower half of Table 7 presents the non-fuel and fuel components of the Alternative Maximum STEM Price for the distillate firing of the gas turbines, as well as parameters of the fuel price as simulated[20]. The road freight cost of distillate is not included in the fuel component as it is considered that this price is largely independent of the price of distillate. This is the same assumption that was used in last year's review.

The price components for the Alternative Maximum STEM Price that provide the 80% cumulative probability price are:

$84.27/MWh + 19.356 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

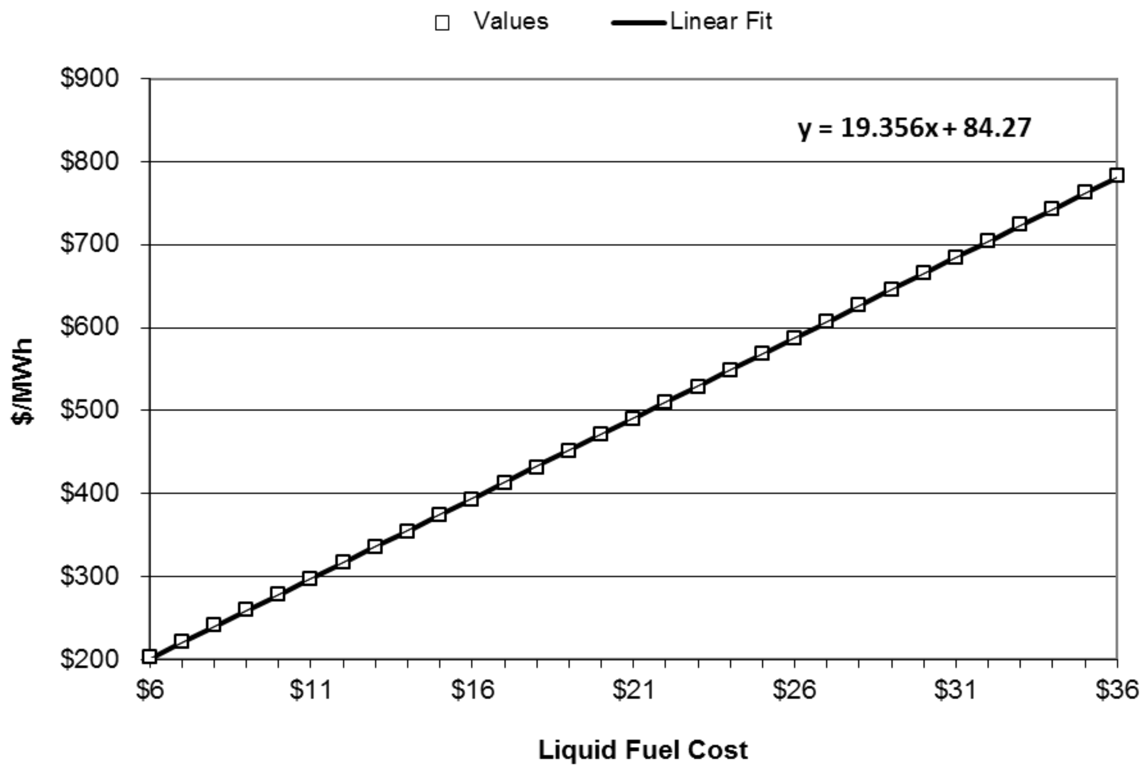
As discussed in section 2.5, the method for selection of the non-fuel and fuel cost factors in the above formula was based upon 10,000 samples of each of the two cost factors combined with a range of fixed distillate prices between $6/GJ and $36/GJ, to assess the 80% probability level of cost for each fuel price[21]. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. This function is shown in Figure 10.

Assuming a Net Ex Terminal distillate price of $13.56/GJ, we calculate a cap price of $347/MWh using the Alternative Maximum STEM Price equation above. This value is based on 80% probability that the assessed cost would not be exceeded for run time events of 6 hours or less and is based on the industrial type gas turbine. The 80% simulated value in Table 7 of $403.70 has been calculated by modelling the uncertainty in distillate price in the simulations. This value is higher than the value obtained with a fixed fuel price.

[20] The percentile values of the fuel and non-fuel components shown in Table 7 are provided for calculating the Alternative Maximum STEM Price. They are not the percentile values of the sampled parameters themselves. For example the 80% value of the non-fuel component in the 10,000 samples was $89.76/MWh and the fuel component 80% value was 19.665 GJ/MWh for the industrial gas turbine. These are not the same values shown in Table 7 ($84.27/MWh and 19.356 GJ/MWh respectively) which used together calculate the 80% value of the Alternative Maximum STEM Price.

[21] The range of fixed distillate prices explored has changed from last year's analysis, when it was from $15/GJ to $45/GJ. The reason for changing the range is that distillate prices have fallen to the point that the expected value of distillate lies below the bottom of last year's range.

Figure 10 80% Probability generation cost with liquid fuel versus fuel cost (using average heat rate at minimum capacity)



4.3 Price components

The Market Rules specify the components that are used to calculate the Energy Price Limits and these have been applied in a statistical simulation. Table 9 summarises the expected values of the various components and the Risk Margin that are required under paragraphs (i) to (v) of clause 6.20.7(b) so that the resulting calculation will provide the assessed Energy Price Limits.

It shows:

- the expected values of each of the cost components that were represented in the cost simulations
- the value of the dispatch cost that would be derived from the mean values of each component and the implied Risk Margin between that average value based calculation and the proposed Energy Price Limits.

It should be noted that the mean and 80th percentile values for the Energy Price Limits cannot be calculated by using the corresponding mean and percentile values for the individual components due to the asymmetry of the probability distributions of the cost components. It may be noted that the “Before Risk Margin” in Table 9 is significantly higher than the expected value of the Dispatch Cycle cost due to these asymmetries.

4.4 Sources of change in the Energy Price Limits

To illustrate the sources of change in the Energy Price Limits since last year’s 2015 review[22], a series of studies was developed with progressive changes in the input parameters from the current parameters to those which were applied in the 2015 review of Energy Price Limits. In each case the first 1,000 simulations were conducted with the same sets of random inputs except where distribution parameters were changed. In such cases, the

[22] Note that the Energy Price Limits actually adopted by AEMO for the 2015/16 financial year were different to the Energy Price Limits calculated in last year’s final report titled “Energy Price Limits for the Wholesale Electricity Market in Western Australia” and dated 13 May 2015. The differences are due to the use of an updated loss factor.

1,000 sampled input values were taken from the analysis used in the 2015 Energy Price Limits review. This ensures that the impact of random sampling error on the assessed changes is minimised. However, it should also be noted that 10,000 Monte Carlo samples were used in this year's analysis. These additional samples have reduced the overall sampling error relative to last year's analysis and this has moved the percentiles calculated in last year's analysis. The changes caused by the increased number of Monte Carlo samples have also been accounted for in the analysis below as a separate item.

The value of the Dispatch Cycle cost was taken which exceeded 8,000 (80%) of the 10,000 samples.

Table 9 Illustration of components of Energy Price Limits based on mean values

Component	Units	Maximum STEM Price	Alternative Maximum STEM Price	Source
Mean Variable O&M	$/MWh	$57.18	$57.18	Mean of Figure 9
Mean Heat Rate	GJ/MWh	19.047	19.098	Mean AHRM plus start-up fuel consumption.[23]
Mean Fuel Cost	$/GJ	$7.57	$13.89	Mean of Figure 5 for delivered gas price distribution
Loss Factor		1.0298	1.0298	Western Power Networks
Before Risk Margin 6.20.7(b)	$/MWh	$195.54	$313.12	Method 6.20.7(b)
Risk Margin	$/MWh	$44.46	$33.88	Difference between the 80th percentile price and the mean price
	%	22.7%	10.8%	By ratio
Assessed Maximum Price	$/MWh	$240.00	$347.00	Energy Price Limit calculation

Not all combinations of old and new inputs were evaluated. The sequence from new parameters back to old parameter values was developed in the order of:

1) The 2016 review case
2) Previous dispatch patterns restored
3) Previous operating and maintenance costs restored
4) Previous loss factor applied
5) Previous distillate cost and standard deviation applied
6) Previous gas commodity cost distribution applied
7) Previous distillate fixed price range applied
8) 1,000 Monte Carlo samples applied
9) The calculation of the 2015 Maximum STEM Price based on the 80% probability of coverage of the Dispatch Cycle cost.

4.4.1 Change in the Maximum STEM Price

Table 10 provides an analysis of the specific changes to show the changes in the Maximum STEM Price and the parameters affected as described in Appendix B. The table describes the successive changes made to the 2016 analysis to convert it back to the 2015 analysis.

[23] The slight difference in mean heat rates (0.27%) is influenced by the 0.27% difference in operating heat rates (refer section 2.5).

Table 10 Analysis of changes to form the waterfall diagram for the Maximum STEM Price

Step	Label in chart	Changes	Parameters affected (Appendix B)
1	New Max STEM Price	The basis for the 2016 Energy Price Limits	
2	New Historical Dispatch Patterns	Capacity, run times and Dispatch Cycle capacity factor based on the data from 1 January 2013 to 31 December 2014, replaces the data from 1 January 2014 to 31 December 2015	CAP, CF, RH, and hence MPR
3	O&M Parameters	The O&M costs for the industrial gas turbines were replaced with the 2015 values	VHC, SUC
4	Loss Factor	Restore loss factor to 2014/15	LF
5	Distillate Price	Distillate price was changed from $13.56/GJ to $18.17/GJ, and the 2014/15 standard deviation was restored	VFC for distillate (gas price cap altered for Maximum STEM Price)
6	Gas Price	The spot gas commodity cost distribution was replaced with the distribution that applied in the 2015 review.	VFC (gas)
7	Distillate range (No effect)	A fixed distillate price in the range of $15/GJ to $45/GJ was applied	VFC (distillate)
8	Sampling	1,000 Monte Carlo samples were used instead of 10,000	All sampled parameters
9	Previous Max STEM Price	The calculation of the Maximum STEM Price based on the 2015 parameters.	

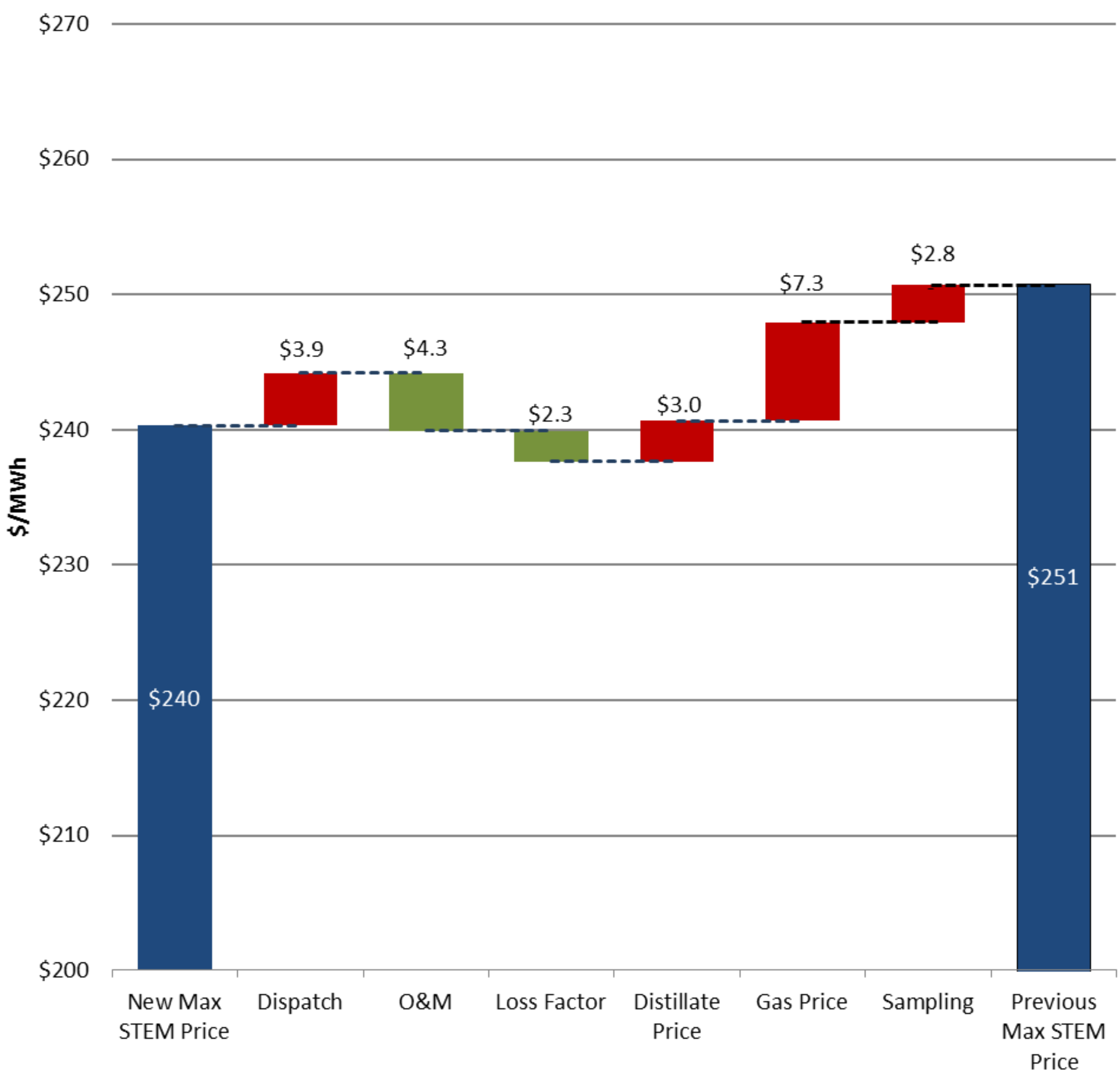
Figure 11 and Table 11 show the relative contribution of the various changes to the Maximum STEM Price since the 2015 review. The greatest difference is in the spot gas price distribution, which is lower in magnitude in this year's review relative to last year's review. The two other factors that have contributed most to the movement in the Maximum STEM Price since last year's review are the increase in the O&M cost, due to the lower exchange rate, CPI escalation and shorter Dispatch Cycle and also a decrease in the Dispatch Cycle cost, which reflects lower start cost (due to the lower fuel usage), but high non-fuel costs which are spread out over lower dispatch levels. A new category of cost contribution to the change in the Maximum STEM Price investigated is the sampling error of using 1,000 samples rather than 10,000 samples. This difference is just over 1% of the total calculated Maximum STEM Price and is a smaller factor than the three factors described above. The sampling error for the 80th percentile for the current study will be lower than that of the previous study by a factor of 3.16, which is the square root of 10.

The relative contributions to the change in the Maximum STEM Price are illustrated in the waterfall diagram in Figure 11.

Table 11 Impact of factors on the change in the Maximum STEM Price

Factor	Impact $/MWh
Dispatch	-$3.87
O&M	$4.26
Loss Factor	$2.26
Distillate Price	-$3.00
Gas Price	-$7.30
Sampling	-$2.77

Figure 11 Impact of factors on the change in the Maximum STEM Price



4.4.2 Change in Alternative Maximum STEM Price

Table 12 provides an analysis of the changes to the Alternative Maximum STEM Price and the parameters affected as described in Appendix B. The table describes the successive changes made to the 2016 analysis to convert it back to the 2015 analysis.

Figure 12 and Table 13 show the relative contribution of the various changes to the Alternative Maximum STEM Price since the 2015 review. The majority of the change has been caused by the reduction in the distillate price. Lesser factors influencing the final outcome are the increase in the number of Monte Carlo samples, the increase in the O&M cost and the loss factor.

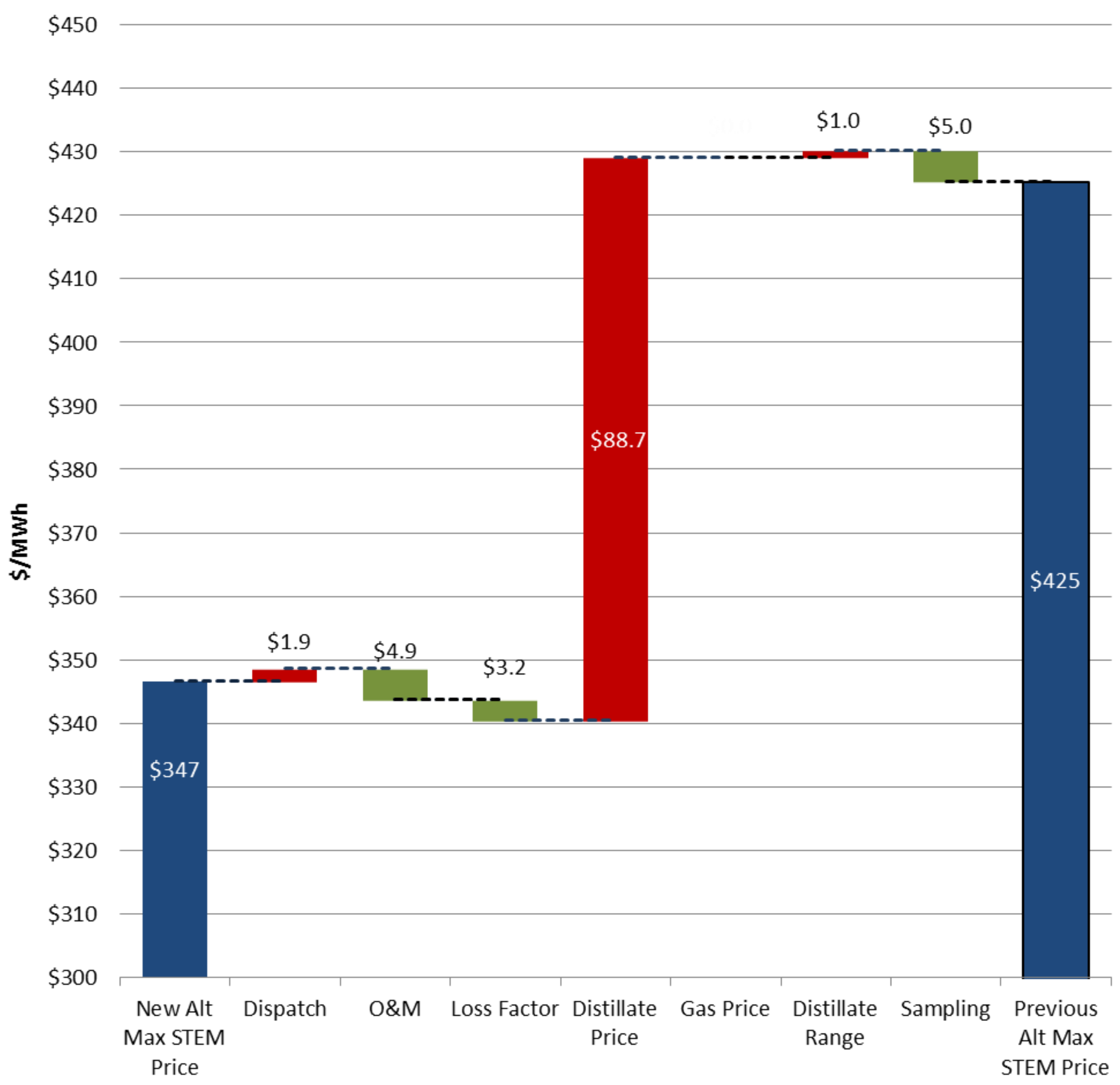
Table 12 Analysis of changes to form the waterfall diagram for the Alternative Maximum STEM Price

Step	Label in chart	Changes	Parameters affected (Appendix B)
1	New Max STEM Price	The basis for the 2016 Energy Price Limits	
2	New Historical Dispatch Patterns	Capacity, run times and Dispatch Cycle capacity factor based on the data from 1 January 2013 to 31 December 2014, replaces the data from 1 January 2014 to 31 December 2015	CAP, CF, RH, and hence MPR
3	O&M Parameters	The O&M costs for the industrial gas turbines were replaced with the 2015 values	VHC, SUC
4	Loss Factor	Restore loss factor to 2014/15	LF
5	Distillate Price	Distillate price was changed from $13.56/GJ to $18.17/GJ, and the 2014/15 standard deviation was restored	VFC (distillate)
6	Gas Price (No effect)	The spot gas commodity cost distribution was replaced with the distribution that applied in the 2015 review.	VFC (gas)
7	Distillate range	A fixed distillate price in the range of $15/GJ to $45/GJ was applied	VFC (distillate)
8	Sampling	1,000 Monte Carlo samples were used instead of 10,000	All sampled parameters
9	Previous Max STEM Price	The calculation of the Maximum STEM Price based on the 2015 parameters.	

Table 13 Impact of factors on the change in the Alternative Maximum STEM Price

Factor	Impact $/MWh
Dispatch	-$1.95
O&M	$4.91
Loss Factor	$3.24
Distillate Price	-$88.73
Gas Price	$0.00
Distillate Range	-$1.03
Sampling	$4.98

Figure 12 Impact of factors on the change in the Alternative Maximum STEM Price



4.5 Cross checking of results

4.5.1 Cross checking Dispatch Cycle costs with heat rate based on market dispatch

Since Rule Change RC_2008_07, the Market Rules refer to the use of the average heat rate at minimum capacity. This has been accepted to ensure that the Energy Price Limits would not restrict the most inefficient practical operation of the gas turbines - that is with loading at the minimum generation level. This has the effect of providing additional margin above the likely actual costs of peaking operation. In this study and previously, Jacobs has also calculated the expected costs using minimum and maximum capacities and associated heat rates and typical dispatch profiles to assess the variation of average heat rate for Dispatch Cycles of different duration and capacity factor. This process is described as the “Market Dispatch Cycle Cost Method” and the method and results are presented in Appendix E. This may be used to assess the probability that the Energy Price Limits will exceed actual Dispatch Cycle costs.

Table 14 shows a tabulation of the mean values of the Dispatch Cycle cost using the average heat rate at minimum capacity as well as the Market Dispatch Cycle Cost method. The results are quite similar, with potential for slight over-estimation of the Alternative Maximum STEM Price by using the heat rate at minimum value. For both the Maximum STEM Price and the Alternative Maximum STEM Price, the values are $1/MWh lower after rounding using the Market Dispatch Cycle Cost Method.

Table 14 Energy Price Limits using average heat rate at minimum capacity or Market Dispatch Cycle Cost Method

	Maximum STEM Price		**Alternative Maximum STEM Price**	
	Average heat rate at minimum capacity	Market Dispatch Cycle Cost method	Average heat rate at minimum capacity	Market Dispatch Cycle Cost method
Mean value	$195.60	$194.16	$313.37	$311.09
80th percentile	$240.25	$239.11	$346.02	$344.63
Margin over expected value	22.8%	23.2%	10.4%	10.8%

The difference between the proposed Energy Price Limits and the Dispatch Cycle costs based on the Market Dispatch Cycle Cost Method for Pinjar is about 10.8% of the expected costs for distillate firing and about 23.2% for gas firing[24]. That the values are similar for the Maximum STEM Price reflects a higher number of short Dispatch Cycles in the historical data. Thus the Market Dispatch Cycle Cost Method is calculating an effective heat rate commensurate with the average heat rate at minimum capacity at the 80% probability of coverage.

[24] Table 14 compares the proposed price caps with the expected average Dispatch Cycle cost and shows the margins as a ratio of the expected average Dispatch Cycle cost, rather than the cost calculated by clause 6.20.7(b). The use of the average heat rate at minimum produces a slightly higher Maximum STEM Price due to the assumption about operation at minimum stable capacity which is not fully reflected in historical dispatch. The difference is immaterial.

5. Public Consultation

A Final Draft Report version 1.4 was published for public consultation. No submissions were received in response to the public consultation process, and as a result no substantial changes have been made in the finalisation of this report.

6. Conclusions

The cost analysis of the short term running of gas turbines in the SWIS has confirmed the need to decrease the Energy Price Limit values on 1 July 2016 from those that apply currently. From 1 July 2016 it is proposed that:

- The Maximum STEM Price should be $240/MWh; and
- The Alternative Maximum STEM Price should be $84.27/MWh + 19.356 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

At $13.56/GJ Net Ex Terminal Price the proposed Alternative Maximum STEM Price is $347/MWh.

The most significant influences on the Alternative Maximum STEM Price have been the decrease in the fuel price, driven by the continuing decrease in the world oil price, and the increase in the variable O&M costs, driven by the reduction in the $AU:$US exchange rate and the applied CPI escalation.

The decrease in the Maximum STEM Price since last year's assessment has primarily been driven by the reduction in the assumed spot gas price distribution. The increase in the variable O&M costs and the decrease in the costs associated with the updated dispatch profile have had a second-order impact on the decrease in the Maximum STEM Price.

Table 15 summarises the prices that have applied since November 2011 and the subsequent results obtained by using the various methods. New values are rounded to the nearest dollar amount.

Table 15 Summary of price caps

No.	History of proposed and published prices	Maximum STEM Price ($/MWh)	Alternative Maximum STEM Price ($/MWh)	Comment
1	Published Prices from 1 November 2011	$314	$533	From AEMO website.
2	Published Prices from 1 July 2012	$323	$547	From AEMO website.
3	Published Prices from 1 July 2013	$305	$500	From AEMO website
4	Published Prices from 1 July 2014	$330	$562	From AEMO website
6	Published Price from 1 July 2015	$253	$429	From AEMO website
7	Published Price from 1 June 2016	$253	$315	From AEMO website[25]
8	Proposed price to apply from 1 July, 2016	$240	$347	Based on $13.56/GJ for distillate, ex terminal.
9	Probability level as Risk Margin basis	80%	80%	

Notes: (1) In row 8, as required in clause 6.20.7(b) these are the proposed price caps to apply from 1 July 2016 based on a projected Net Ex Terminal wholesale distillate price of $0.926/litre excluding GST ($13.56/GJ).
(2) In row 9, the probability levels that are proposed to be applied to determine the Risk Margin for setting the price caps in accordance with the Market Rules.

[25] http://wa.aemo.com.au/home/electricity/market-information/price-limits, last accessed 3 June 2016.

Appendix A. Market Rules related to maximum price review

This appendix lists the Market Rules that determine the review of maximum prices in the WEM. The relevant Market Rule clauses are provided below:

6.20.6. AEMO must annually review the appropriateness of the value of the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.7. In conducting the review required by clause 6.20.6 AEMO:

a) may propose revised values for the following:

i. the Maximum STEM Price, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas and is to be calculated using the formula in paragraph (b); and

ii. the Alternative Maximum STEM, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by distillate and is to be calculated using the formula in paragraph (b);

b) must calculate the Maximum STEM Price or Alternative Maximum STEM Price using the following formula:

(1 + Risk Margin) x (Variable O&M +(Heat Rate x Fuel Cost))/Loss Factor

Where:

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW open cycle gas turbine generating station expressed in $/MWh; and include, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the Reference Node.

Where AEMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.9. In conducting the review required by clause 6.20.6 AEMO must prepare a draft report describing how it has arrived at a proposed revised value of an Energy Price Limit. The draft report must also include details of how AEMO determined the appropriate values to apply for the factors described in clause 6.20.7(b)(i) to (v). AEMO must publish the draft report on the Market Web-Site and advertise the report in newspapers widely published in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users, within six weeks of the date of publication.

6.20.9A. Prior to proposing a final revised value to an Energy Price Limit in accordance with clause 6.20.10, AEMO may publish a request for further submissions on the Market Web Site. Where AEMO publishes a request for further submission in accordance with this clause, it must request submissions from all sectors of the Western Australia energy industry, including end-users.

6.20.10. After considering the submissions on the draft report described in clause 6.20.9, and any submissions received under clause 6.20.9A, AEMO must propose a final revised value for any proposed change to an Energy Price Limit and submit those values and its final report, including any submissions received, to the Economic Regulation Authority for approval.

6.20.11. A proposed revised value for any Energy Price Limit replaces the previous value after:

a) the Economic Regulation Authority has approved that value in accordance with clause 2.26; and

b) AEMO has posted a notice on the Market Web Site of the new value of the applicable Energy Price Limit,

with effect from the time specified in AEMO's notice.

Appendix B. Formulation of the Maximum STEM Price

B.1 Formulation of the Energy Price Limits

The following represents the formulae used to model the formula in clause 6.20.7(b) of the Market Rules, excluding the Risk Margin factor, broken down into the full set of sub components. It is the formulae below that are used to calculate the 10,000 plus samples used to create the probability curve for the Energy Price Limits. The primary formula below includes the start-up fuel cost, the start operating cost and the fuel cost components.

Cost = (VHC * RH / MPR + AHRM * (VFTC+ (FT + VFC * FSR)/VFTCF)
+(SUC + SUFC * (VFTC + (FT + VFC * FSR)/VFTCF))/MPR)/ LF

Where:

Cost is the sampled estimate of the average marginal cost of a Dispatch Cycle including the start-up costs on the basis that the start-up costs are part of the cost associated with the decision to start operating a unit.

VHC is the variable hourly running cost when maintenance costs are based on running hours;

RH is the running hours per Dispatch Cycle based on a sampled distribution derived from market observations of dispatch. This distribution is confidential and is not included in this report, apart from the average of 106.9 hours for Parkeston shown in Table D- 4;

MPR is the MWh generated per run based on a sampled distribution derived from market observations and derived as a function of run time. This distribution is confidential and is not included in this report, apart from the average value of 3,495 MWh for Parkeston shown in Table D- 4;

MPR = CAP * RH * CF

AHRM is the average heat rate at minimum capacity in GJ/MWh sent out (or a dispatch based calculation of average heat rate when that alternative method was applied);

VFTC is the variable fuel transport cost in $/GJ;

FT is the fixed fuel transport cost in $/GJ;

VFC is the variable fuel cost in $/GJ in the range $2/GJ to $19.6/GJ or lower if the break-even price with distillate is lower;

FSR is the reference spot gas supply capacity factor (taken as 100%);

VFTCF is the spot gas supply daily capacity factor as modelled as a probability distribution between 60% and 100%;

SUC is the cost per start ($/start) when maintenance costs depend on the number of starts per year using the time discount formulation:

$$CPS(i) = X(i) \times \frac{SPY \times (1 - (1 + DR)^{\frac{-CL}{SPY}})}{CL \times \ln(1 + DR)}$$

SUC = Sum [CPS(i)]

Where:

CPS(i) is the cost per start for each maintenance stage (i)

Sum [CPS(i)] is the summation of the values of CPS(i) for all of the maintenance stages (i) in the full cycle.

X(i) is the maintenance expenditure for each maintenance stage

DR is the discount rate taken to be 9% per annum (pre-tax real);

CL is the maintenance cycle length at 2400 starts;

SPY is the sampled number of starts per year;

Log is the natural logarithm.

SUFC is the start-up fuel consumption to get the plant up to minimum stable generation in GJ;

CAP is the plant sent-out capacity in MW. The capacity is derived from a distribution of maximum output of the generator units which is derived from market data.

CF is the capacity factor of the Dispatch Cycle derived from the capacity factor versus run time based on a regression function derived from historical operating data from January 2014 to December 2015 inclusive.

LF is the loss factor.

The variable fuel cost of gas (VFC) was capped to the price which would give the same Dispatch Cycle cost as the prevailing price of distillate sampled from the distillate price distribution.

The primary formula above may be split into the two components (fuel and non-fuel dependent) for the calculation of the Alternative Maximum STEM Price as follows.

The non-fuel component is based on non-fuel start-up costs, distillate road freight, and the variable O&M cost as applicable:

AMSP Non-fuel Component = ((VHC * RH / MPR + SUC)/MPR + (AHRM + SUFC/MPR) * VFTC)/LF

The fuel dependent component for the Alternative Maximum STEM Price cost is derived from the following components:

AMSP Fuel Component = (AHRM * (FT + VFC * FSR)/VFTCF + SUFC * (FT + VFC * FSR)/VFTCF/MPR)/ LF

After removing the zero and unity terms applicable to distillate, the fuel component is:

AMSP Fuel Component = (AHRM * VFC + SUFC * VFC /MPR)/ LF

The effective Fuel Cost Coefficient may be derived by dividing by the Net Ex Terminal fuel cost (VFC):

AMSP Fuel Cost Coefficient = (AHRM + SUFC/MPR)/LF

Note that the percentile value of these coefficients is derived from these sampled values so that the 80% value is obtained as discussed in section 4.2.

The treatment of these variables as stochastic variables is summarised in Table B.1. The means, minima and maxima and standard deviations for the heat rate (AHRM) were as derived from the Dispatch Cycle parameters based on the minimum capacity level. Over the 10,000 samples, the normal variables were typically between ±4 standard deviations unless clipped to a smaller range around the mean. The sampled number of starts per year was given a minimum value of 10. The start-up cost SUC, MPR, run times RH and plant sent-out capacity CAP and Dispatch Cycle capacity factor CF were derived from confidential market data. The start-up cost SUC depends on the distribution of the number of starts per year for the industrial gas turbines. The loss factor LF was as published by Western Power Networks for 2015/16. The start-up fuel consumption was based on the estimates developed by Jacobs.

Table B.1 Structure of the stochastic model of cost

Variable	Mean/Mode	Sampled Minimum	Sampled Maximum	Standard Deviation	Distribution Type	Comment
VHC	169.00	$104	$238	10%	Normal	Aero-derivative - Goldfields
AHRM	12.062 GJ/MWh	10.091	24.440	0.828 *	Normal	Aero-derivative – Goldfields (including variation due to minimum capacity uncertainty)
AHRM	18.913 GJ/MWh	15.46	28.17	1.337 *	Normal	Industrial – Pinjar (parameters obtained from the sampled distribution including variation due to minimum capacity uncertainty)
VFTC	$2.233	$1.437	$3.437	$0.270 *	Truncated lognormal	Aero-derivative - Goldfields
VFTC	$1.796	$1.000	$3.000	$0.270 *	Truncated lognormal	Industrial
FT	$5.74	$5.74	$5.74		None	Aero-derivative
FT	$0.00	$0.00	$0.00		Fixed	Industrial
VFC	$5.54	$0.40	$12.50	$1.800 *	Truncated normal	Gas supply after break-even price capping
FSR	100%	100%	100%		Fixed	
VFTCF	89.9%	61%	100%	6.86% *	Truncated lognormal	VFTCF = 1 for distillate
SUFC	3.53 GJ	2.142	4.752	10%	Normal	Aero-derivative
SUFC	3.50 GJ	2.121	4.704	10%	Normal	Industrial
SUFC	3.54 GJ	2.148	4.765	10%	Normal	Aero-derivative (liquid fuel)
SUFC	3.51 GJ	2.126	4.717	10%	Normal	Industrial (liquid fuel)

Note: * These standard deviation values refer to the values as sampled within the limited range.

Appendix C. Gas prices in Western Australia in 2016-17

C.1 Introduction

Jacobs considers the spot gas price to be the relevant price for use in the calculation of the Maximum STEM Price as it represents the opportunity cost of gas used by the marginal gas fired peaking unit. If surplus to requirements, the spot gas price represents the value that could be extracted through sale of gas in this market. This is consistent with the approach adopted in previous Energy Price Limit reviews.

This section presents Jacobs's assessment of the appropriate spot gas price range to apply in the derivation of the Maximum STEM Price. The assessment is based on publicly available information regarding gas prices in WA. Jacobs has estimated the 2016-17 gas price distributions using its own statistical approach.

C.2 The WA gas market

In WA gas is bought and sold predominantly on a term contract basis, with terms ranging from under one year to over 15 years. Contracts provide for annual and daily maximum quantities and annual minimum quantities also known as take-or-pay volumes. Contract details are confidential but for many contracts quantities and/or prices can be estimated from company press releases and other sources.

Buyers nominate daily quantities to be injected into pipelines on their behalf (up to the maximum limit) based on what they intend to withdraw and imbalances are managed by adjusting subsequent nominations up or down. If cumulative imbalances exceed a threshold, the pipeline may charge a penalty – on the major WA pipeline, the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the thresholds are relatively generous.

Shorter-term trades arise when parties want to vary their offtake volumes above maxima or below minima or avoid penalty payments. This can be done through over-the-counter trades or through exchanges, of which there are currently three third party exchanges in WA[26]:

- The Inlet Trading market operated by DBNGP at the inlet to the pipeline, which enables pipeline shippers to trade equal quantities of imbalances.
- The gasTrading platform, which enables prospective buyers and sellers to make offers to purchase and bids to sell gas on a month-ahead basis at any gas injection point. gasTrading matches offers and bids and the gas is then scheduled, with subsequent daily adjustments.

  gasTrading's website provides information regarding volumes and prices of trades. For the past three years, typical volumes traded range from 5TJ/d to 25TJ/d (0.5% to 2.5% of WA domestic gas volumes) and prices paid range from $2.00/GJ to $7.50/GJ. The market does not settle at a single daily price but a range of prices reflecting a series of bilateral transactions.
- The gas trading platform operated by Energy Access Services since 2010. Energy Access has nine members but usage of the platform is unknown.

The reasons parties may choose to participate in each of the above alternatives may include preferences to deal directly with counterparties, their scale of trading, preferred periods of trades (daily, monthly) etc.

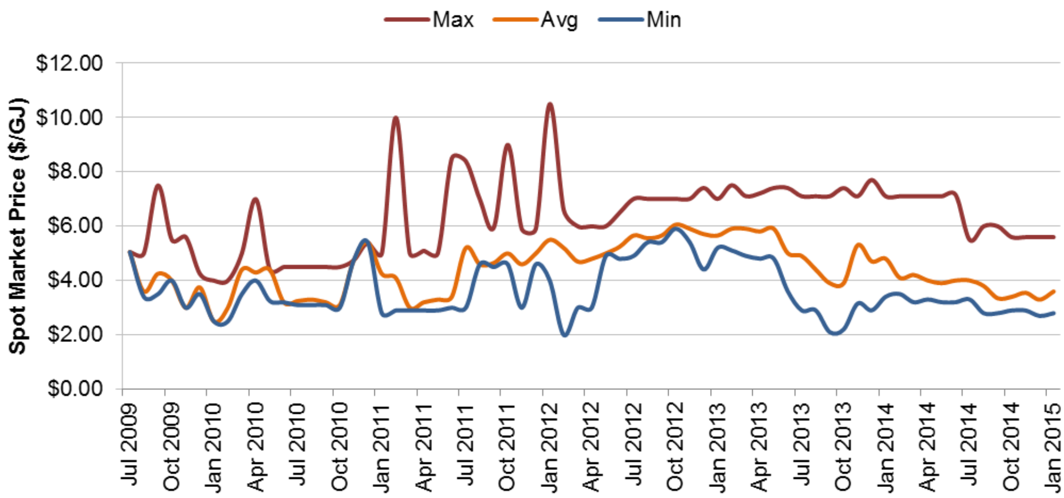
C.3 Estimating future gas spot market prices

Jacobs believes that the most appropriate approach to projecting future spot prices for use in setting the Maximum STEM Price is to consider the recent spot market data available, as well as the measure by which further developments are likely to influence this market. Ideally, spot prices would include estimates of all spot prices discussed above, including those which are not published. For the non-published prices this would involve a rigorous survey of market participants, to avoid using potentially unreliable anecdotal information. However this has not been possible within the time frame of this review. Consequently Jacobs has used gasTrading's spot prices as representative of the spot market as a whole.

[26] There are also a number of privately run exchanges for which data is not available.

During the previous review, Jacobs updated the methodology by which the distributions of future gas spot market prices are estimated, as the previous method produced forecast price distributions that did not appear to align with market outcomes. Jacobs has based this year's modelling on the 'alternative' forecast methodology developed during last year's review, which predicts the gas price distribution as a function of the historical maximum monthly spot gas prices.

Figure C- 1 gasTrading spot market monthly price history



Source: gasTrading website.

As evidenced from the data in Figure C- 1, average and minimum gas market prices have seen a gradual decrease from their peak in October 2012. In addition, the maximum price for gas exchanges through this market has become much more stable since October 2012, with much less volatility than previously. Between then and July 2014, the maximum price was seemingly capped at $7/GJ, which decreased on July 2014 to $5.60/GJ. Based on this data, Jacobs has carried out analysis to understand the drivers behind the spot market exchanges. In addition, using consumption and transmission data, a number of market dynamics have been identified which are likely to underpin the gas spot market in WA in the short term.

C.4 Factors affecting gas spot market trades and prices

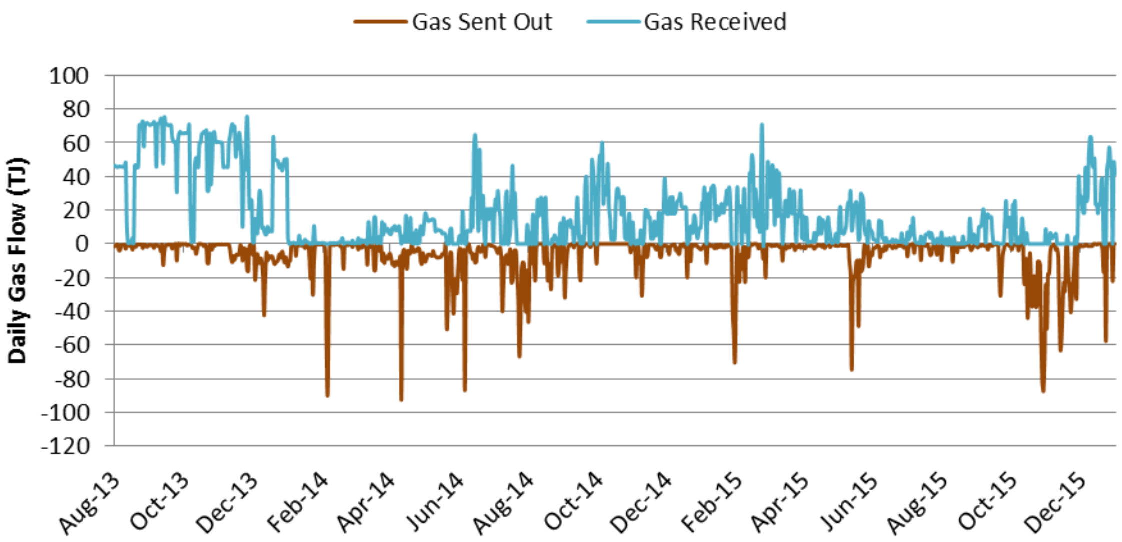
Electricity demand

In the previous year's study, Jacobs examined the relationship between peak electrical demand and high spot gas prices, on the basis that the higher demand for gas from peaking plant may have a significant impact on the spot gas price. However, only a weak correlation between the two was observed, indicating that other short-term factors dominate the spot market price.

Mondarra storage

The Mondarra Storage operated by the APA Group (APA) commenced operations in 2013. Gas storages serve two functions: emergency supply when production or pipeline capacity is accidentally lost, and provision of additional peak or seasonal supply subject to availability of pipeline capacity from the storage to end-users. The latter function also involves price arbitrage, because gas is stored during lower price periods and re-used during higher price periods, assuming low/high prices correlate with low/high demand or high/low supply. At a time of generally rising prices lower cost gas can also be stored for future use in a longer timeframe. Figure C- 2 shows the changes in operation of the Mondarra storage plant since August 2013. It can be observed that the first period of operation consisted of drawing gas from the market to build up its gas storage. Closer inspection of the data suggests that there is no contract in place as the injection and withdrawal of gas by the facility may be displaying an opportunistic pattern.

Figure C- 2 Mondarra Gas Storage Facility Operations, Aug 2013 to Dec 2015



Source: IMO Gas Bulletin Board.

The impact of Mondarra should be a reduced cost of gas supply, including gas spot prices. In particular, we would expect price volatility to be reduced with the introduction of the storage facility, as extreme prices present an arbitrage opportunity.

Future gas prices

Noting that the most recent review from AEMO in relation to the gas market concludes that the domestic gas market is well supplied for the period to 2020, future gas prices will be driven by international LNG prices and the export demands. The data for March 2016, shown in Table C- 1 describes that of a market willing to purchase an amount of gas above that offered in the market, reflecting a supply side with higher values placed on gas sold in a future period.

Table C- 1 Supply-demand summary for gasTrading spot market

	Offers to Purchase	Scheduled for Sale
Total Quantity (TJ)	417	160
Average Price /GJ	$3.24	$3.73
Highest Price /GJ	$4.25	$4.25
Lowest Price /GJ	$2.85	$3.10

It is expected that the sustained decrease in oil price will continue to keep LNG prices low, as the gas price on most LNG export contracts are linked to the oil price. Correlation analysis performed by Jacobs suggests that the spot gas prices in WA are reasonably well correlated to the price of Brent Crude denominated in US dollars[27], which implies a link between the spot gas price and the oil price, and in turn implies a link between the spot gas price and the contract gas price, which is also linked to the oil price. Any expected forward price movement on contract gas prices, as would be, for example, projected in the WA GSOO, would therefore also be expected to flow through to spot prices, albeit with an appropriate dampening factor.

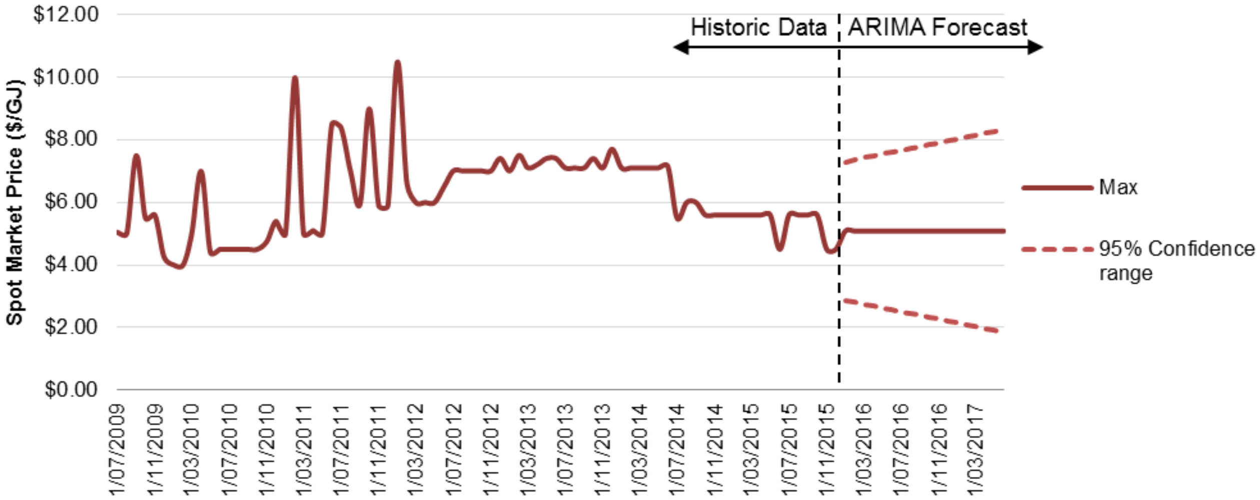
[27] A correlation coefficient of 0.54 was observed for the average monthly spot gas price, and a coefficient of 0.57 was observed for the maximum monthly spot gas price.

C.5 Forecasting the average, minimum and maximum spot market prices

For the forecast of the gas price distribution for the period 2016/17 Jacobs has modelled the forecast prices using a standard ARIMA time-series model, which is widely considered reliable for short term projections. The historical spot market maximum price is used as the basis of the model, which produces a range of prices that future maximum spot gas prices are likely to fall within. Once this forecast range is calculated, a normal distribution has been fitted to the prediction series, which best represents the expected probability density curve of spot prices based on the market forces considered in this study.

For the ARIMA model, the historical data has been obtained from the gasTrading market website. The spot market experienced a high level of volatility from 2009 to early 2012. After this period the maximum price settled down and has maintained low variability. The average and minimum prices show a downward trend in pattern, although in the last few months this trend has levelled off somewhat. Based on these trends, the forecast suggests stable price outcomes, with the maximum spot price rising slightly throughout the year. The level of uncertainty around the forecast has been used to derive the standard deviation of the spot gas price distribution. The projection shows increasing uncertainty over time, which is typical of an ARIMA forecast.

Figure C- 3 gasTrading spot market daily price history and ARIMA forecast



Source: gasTrading website; Jacobs analysis.

C.6 Forecast of WA gas spot market price distribution

The gas price distribution was derived by using the maximum monthly prices and monthly standard deviations obtained from the ARIMA model described in section C.5. The historical maximum prices from July 2009 to December 2015 and the forecast maximum prices for the 2016/17 financial year from the ARIMA model are illustrated in Figure C- 3 together with the upper and lower 95% confidence intervals.

These monthly parameters (monthly maximum prices and monthly standard deviations) were used to derive a normal distribution of gas prices for each month, A composite normal distribution was then derived for financial year 2016/17 from the 12 monthly distributions. The composite distribution was also normal, having a mean price of $5.08/GJ and a standard deviation of $1.77/GJ.

A limitation of the ARIMA modelling is that it can only project future price trends based on the information contained in the historical price time series. It is not able to represent other factors, such as expected movements in the gas contract price or the oil price, or foreseeable shifts in the supply/demand balance, that may also have an impact on future spot prices. Based on feedback on the initial gas price forecast (having a mean of $5.08/GJ), Jacobs further explored the potential influence of the crude oil price on the gas spot price, as crude oil is expected to increase over the short to medium term.

A reasonably strong correlation (with a correlation coefficient of 0.57) was found to exist between the Brent crude oil price denominated in US dollars and the historical maximum monthly spot gas prices in WA. With the expectation that the recent upwards trend in the Brent crude oil price will continue in the short to medium term, Jacobs considered it reasonable to add an uptrend to the maximum monthly spot gas price forecast to represent the expected movements in the oil price.

Jacobs has applied a pass through of 50% of the expected movement in the contract gas price[28] through to the maximum monthly spot gas price. The limitation to 50% is due to the imperfect correlation between the Brent crude oil price and the maximum monthly spot gas price and also not to pass through other factors influencing contract prices that do not necessarily impact on spot gas prices. The expected increase in the 2017 contract gas price relative to the 2016 price is $0.92/GJ. Jacobs therefore added $0.46/GJ to the mean of the projected spot gas price distribution and has kept the same standard deviation. Gas prices are therefore represented as a normal distribution with a mean of $5.54/GJ and a standard deviation of $1.77/GJ.

The adjusted composite gas price distribution is shown in Figure C- 4, which shows that some gas prices under this distribution fall below the $2/GJ gas floor price adopted for this analysis. In these cases the $2/GJ floor has not been applied in the modelling because this part of the distribution will not contribute to the 80th percentile anyway. A refinement could be to model a $2/GJ gas price floor, but its impact will only be to have a slight impact on the mean of the sampled distribution.

Figure C- 4 Forecast of WA gas spot market distribution

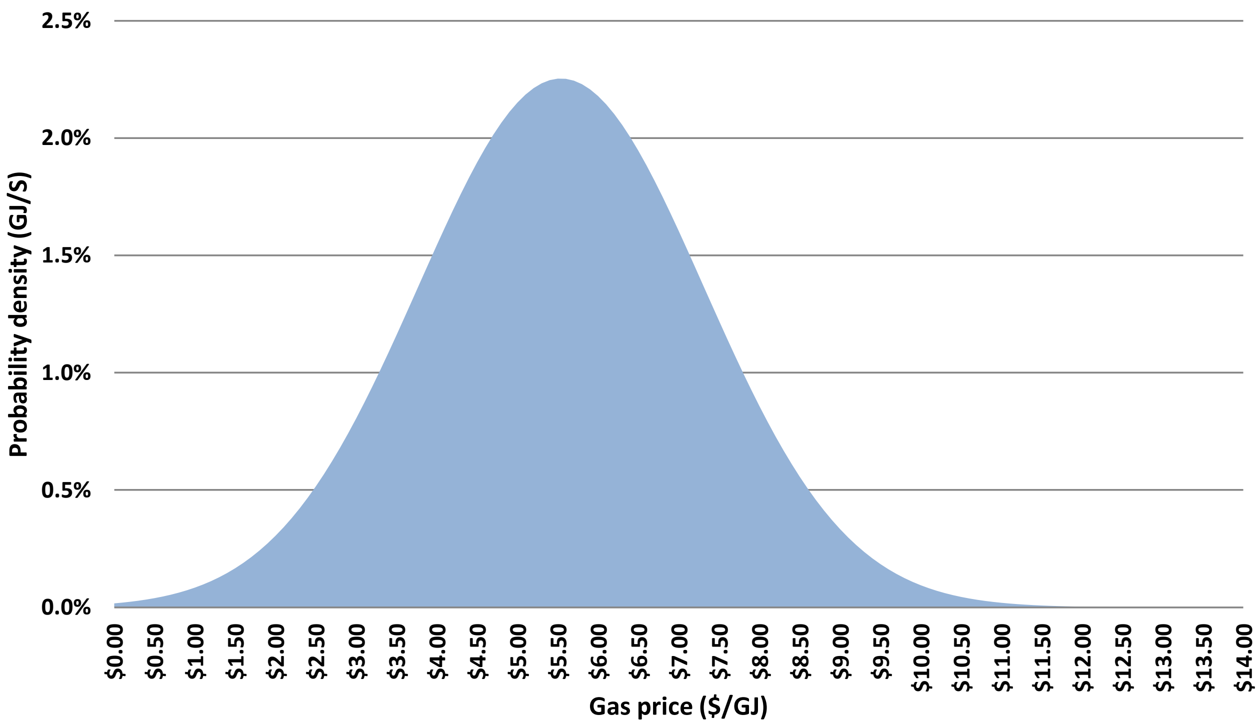


Table C- 2 compares the gas price forecast with last year's gas price forecast.

Table C- 2 Comparison of forecast gas distribution statistics

[28] IMO, *Gas Statement of Opportunities*, Nov 2015, p.90.

Parameter	Jacobs 2015/16	Jacobs 2016/17	Change 2015/16 to 2016/17
Average	$6.04	$5.54	-$0.50
Median (50th percentile)	$6.04	$5.54	-$0.50
80% lower bound (10th percentile)	$4.09	$3.37	-$0.72
80% upper bound (90th percentile)	$7.98	$7.81	-$0.17

C.7 Gas Transmission Costs

C.7.1 Transmission tariffs

Transmission costs on the two pipelines considered in this Energy Price Limit review are set by a combination of regulation by the Economic Regulation Authority under the National Gas Regulations (NGR) and negotiation between the pipeline operators and gas shippers.

C.7.1.1 Dampier Bunbury Natural Gas Pipeline

Although the DBNGP is a Covered (regulated) pipeline, the tariffs until 2016 were set by negotiation between the pipeline and shippers, to cover recent capacity increases. The standard full haul (T1) tariff applicable to delivery into the Perth region as at 2/3/2015 at 100% load factor was $1.552121/GJ[29]. The tariff is comprised of two components, a reservation component charged on capacity reserved and set at 80% of the aggregate, and a commodity component charged on volumes shipped, set at 20% of the aggregate.

The tariff escalates from 1 January 2011 until 1 January 2016 at CPI-2.5%[30], and otherwise at CPI[31]. Based on this, we assume that it will have an average value of $1.548654/GJ over the 2016/17 financial year, which is the average of the estimated 2016 and 2017 tariffs, assuming future CPI escalation of 2.0%. This is slightly lower than the 2014 tariff because the CPI rate in 2015 tracked well below 2.5% for the year, and this reduced the tariff.

C.7.1.2 Goldfields Gas Pipeline

Capacity on the GGP is partly covered and partly uncovered. Covered capacity amounts to 109 TJ/d with the current delivery configuration, of which 3.8 TJ/d was uncontracted as at 1 January 2010. Uncovered capacity, which relates to recent expansions, is estimated to be approximately 91 TJ/d following an expansion in 2013. The regulated tariffs for the Covered capacity are shown in Table C- 3 for the base year and for 2016 and 2017, together with the total charge in Kalgoorlie (distance 1380km). The toll and capacity reservation charges are both applied to capacity. Toll charges for 2016/17 financial years are the average of the 2016 and 2017 calendar years.

Table C- 3 GGP tariffs

	Toll Charge $/GJ	Capacity Reservation Charge $/GJ/km	Throughput charge $/GJ/km	Cost at 100% load factor in Kalgoorlie $/GJ
Covered capacity, Base tariff (June 1997)[32]	$0.243512	$0.001685	$0.000634	$3.44

[29] DBNGP Access Guide, 10 February 2014.
[30] ACIL Tasman, *Gas prices in Western Australia*, February 2012; available at http://wa.aemo.com.au/docs/default-source/rules/other-wem-consultation-docs/2012/2012_review_of_gas_prices_in_the_wem_draft_report_for_consultation.pdf?sfvrsn=2.
[31] DBP Standard Shipper Contract – Full Haul T1, February 2015.
[32] Quoted on GGP website.

Covered capacity, 2016	$0.392881	$0.002719	$0.001023	$5.56
Covered capacity, 2017	$0.401092	$0.002775	$0.001044	$5.67
Covered capacity, 2016/17	**$0.396986**	**$0.002747**	**$0.001034**	**$5.61**

C.7.2 Spot transportation

C.7.2.1 Dampier Bunbury Natural Gas Pipeline

The DBNGP offers capacity on a spot basis[33] to shippers, via a bidding process in which:

- DBP sets capacity available and the minimum price
- Shippers bid prices and volumes
- Capacity is allocated to the highest bid, then the next highest until the capacity is sold or all bids are satisfied.

No data is available on price outcomes but we understand that the minimum price is typically set 15% above the T1 tariff rate. In the current climate of capacity being in excess of transport requirements we would expect limited demand for spot capacity and correspondingly low prices.

C.7.2.2 Goldfields Gas Pipeline

To the best of our knowledge GGP does not systematically offer capacity on a spot basis. For previous Energy Price Limit reviews, ACIL Tasman has suggested that "it would be possible for an existing shipper to gain access to limited volumes of spot capacity for a small premium above the existing indicative tariffs"[34]. It is therefore reasonable to believe both APA and existing shippers would only offer spare capacity above the covered capacity price level. GBB data suggests there is at least 25 TJ/d unused capacity which supports the assumption that access to small volumes of spot capacity would be possible.

C.7.3 Transmission costs

The accepted practice in previous Energy Price Limit reviews has been to use the following transmission costs:

- For DBNGP, the estimated minimum spot price converted into a range by adding a lognormal distribution with a standard deviation of $0.15/GJ.
- For GGP, a 10% premium on the covered estimate at 100% load factor, that is, $6.18/GJ for 2016/17.

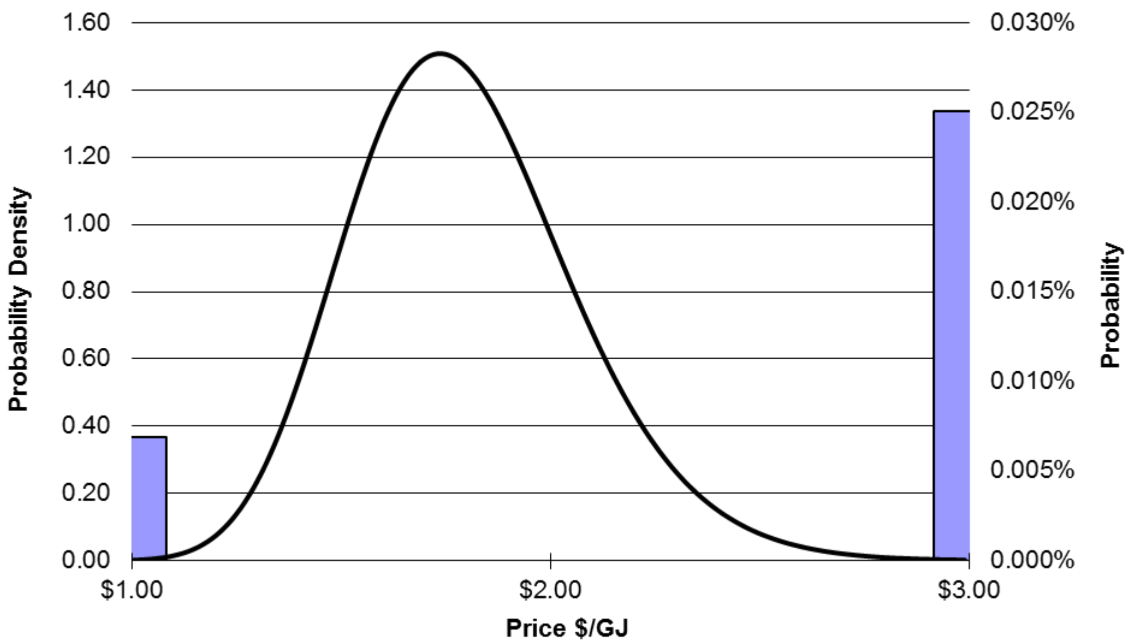
For the gas transport to Perth on DBNGP, the lognormal distribution assumed has an 80% confidence range being between $1.46/GJ and $2.15/GJ with a most likely value (mode) of $1.736/GJ. The mean value of the transmission charge is $1.796/GJ. The distribution shown in Figure C- 5 represents this uncertainty in the gas transport cost. The gas cost range was taken between $1/GJ and $3/GJ which is consistent with the assumptions adopted in the 2014 and 2015 reviews.

Gas delivered via the GGP is sourced from production plants that inject gas into the DBNGP and directly into the GGP. Gas injected into the DBNGP is backhauled or part-hauled to the inlet of the GGP. As no backhaul or part-haul spot capacity is offered by DBNGP, the DBNGP spot price is added to the cost of delivering gas to Kalgoorlie. This simplistic assumption may lead to an overestimation of the gas transport cost to Parkeston since it is not known what proportion of gas to the power station is injected directly into the GGP and/or into the DBNGP. Given that the Parkeston aero-derivative units do not currently set the Maximum STEM Price, this

[33] Details were provided in DBP's evidence to the WA Parliamentary Inquiry into Domestic Gas Prices in 2010.
[34] ACIL Tasman, *Gas Prices in Western Australia: 2013-14 Review of inputs to the Wholesale Energy Market*, February 2013, p.10.

conservative assumption is considered reasonable for this analysis, but may need to be reconsidered should the Parkeston units become genuine candidates for setting the Maximum STEM Price in the future.

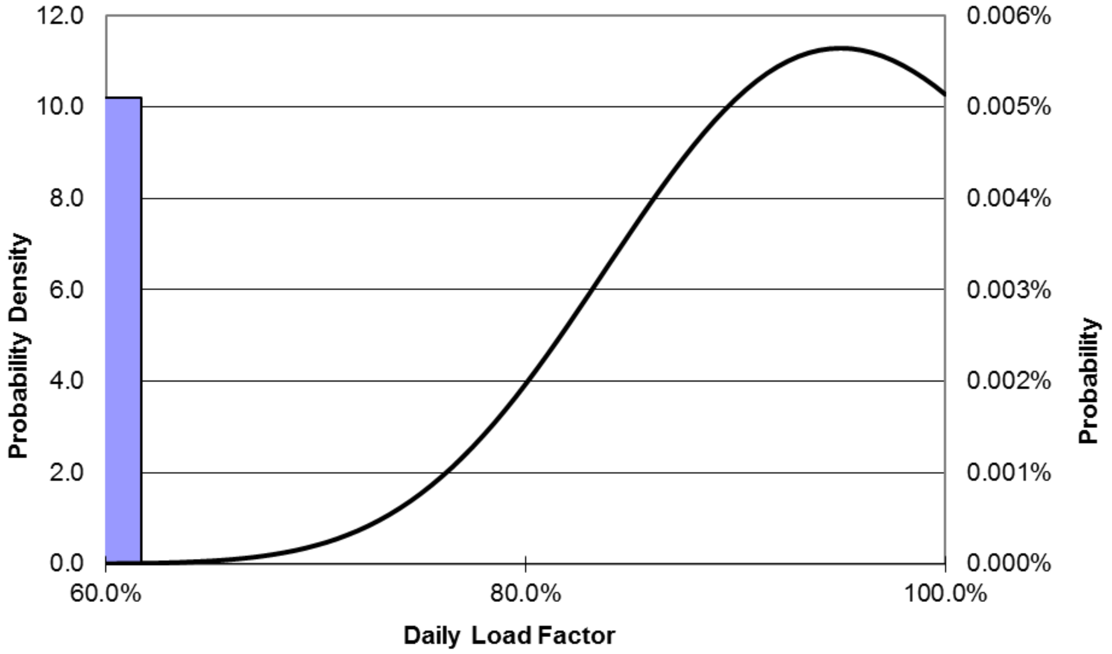
Figure C- 5 Capped lognormal distribution for Dampier to Bunbury Pipeline spot gas transport cost



C.8 Daily gas load factor

The probability distribution used to represent the uncertainty of the daily gas supply load factor is shown in Figure C- 6. The mode of the continuous distribution is at 95% with an 80% confidence range between 80% and 98%. There is a 0.005% probability of a value at 60%. The mean of the composite daily load factor distribution is 89.91%. This is consistent with the model provided by ACIL Tasman for the 2013 review and was also used in the 2014 and 2015 reviews by Jacobs.

Figure C- 6 Capped lognormal distribution for modelling spot gas daily load factor uncertainty



Appendix D. Energy Price Limits based on aero-derivative gas turbines

This appendix presents the analysis for the Parkeston gas turbines and compares it with the base calculations for Pinjar gas turbines shown in Chapters 3 and 4.

The calculations were substantially the same as for the industrial gas turbines except that:

- The gas transportation cost is supplemented by the Gas to the Goldfields Pipeline (GGP)
- The distillate road freight cost is greater given the larger distance travelled (5.4 Acpl excluding GST and excise compared to 1.3 Acpl for Pinjar)
- The O&M cost is determined by running hours instead of starts
- There is a 44% cost penalty on the variable O&M cost for liquid firing because the aero-derivatives require more frequent maintenance when liquid fired. This arises from the Hot Rotable exchange which is required every 12,500 hours for liquid firing instead of 25,000 for gas firing.
- The transmission loss factor differs for Parkeston (1.1896)
- The assumed heat rate and start-up fuel consumption differs for Parkeston as described in Section D.4 below

The following sections discuss these differences in input data where not already commented on.

D.1 Run times

The frequency of starts and run times for Parkeston do not appear to have materially changed in the past 12 months. The evidence is presented in the confidential Appendix for AEMO.

The run times of the peaking units have been analysed from the market data from 1 January 2014 to 31 December 2015. A probability density function has been derived which represents the variation in run times until 31 December 2015.

D.2 Gas transmission to the Goldfields

Having assessed the likely conditions for spot trading of gas transmission capacity, Jacobs have concluded that the appropriate prices for delivery to the Goldfields from 1 July 2016 should be $6.18/GJ plus the DBNGP transport price with an 80% confidence range between $1.46/GJ and $2.15/GJ for transport to the Perth region. There is virtually no uncertainty about the price of spot transport to the Goldfields. This GGP tariff consists of a fixed component of $5.74/GJ which is divided by the daily load factor and $0.44/GJ which is variable and unaffected by the daily gas supply load factor.

The resulting modelled delivered gas price as compared with the equivalent delivered price for the industrial gas turbines at Pinjar is shown in Figure D- 1. The modelled delivered gas price for the Goldfields region had an 80% confidence range of $10.58/GJ to $16.31/GJ with a mode of $10.90/GJ and a mean of $13.32/GJ. The key features of the delivered gas price for Parkeston are provided in Table D- 1.

Figure D- 1 Sampled probability density of delivered gas price for peaking purposes

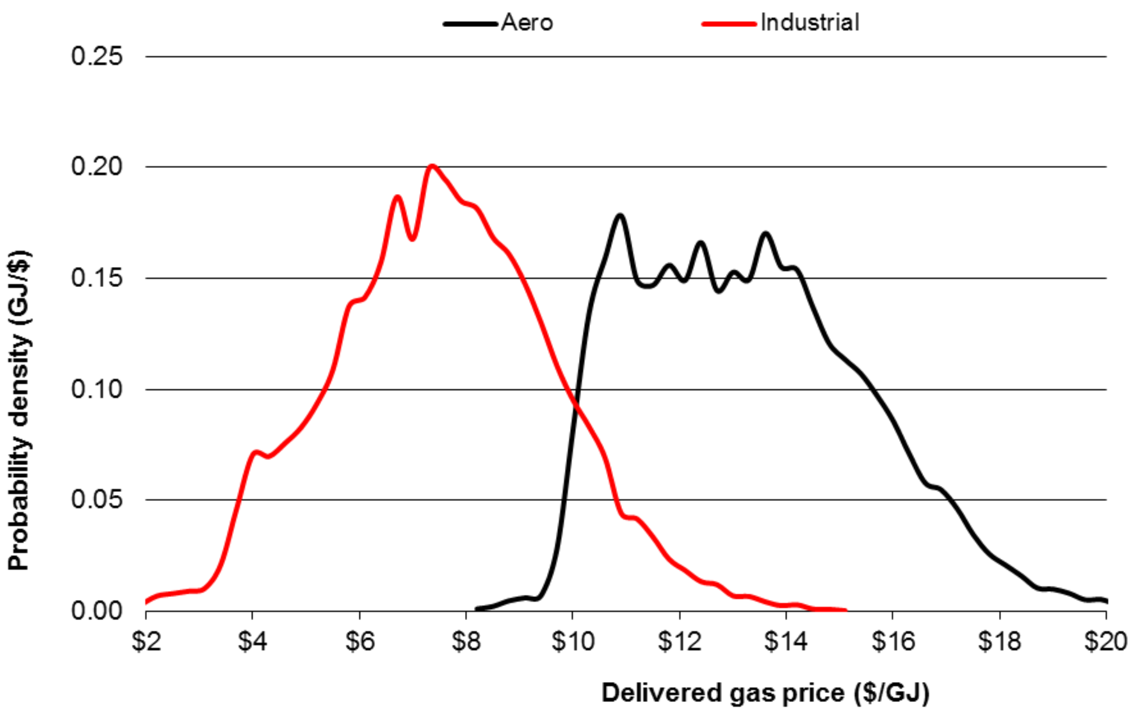


Table D- 1 Delivered gas price for Parkeston gas turbines

Delivered Gas Prices as Modelled	
	Parkeston
Min	$7.93
5%	$10.24
10%	$10.58
50%	$13.15
Mean	$13.32
Mode	$10.90
80%	$15.25
90%	$16.31
95%	$17.22
Max	$22.77

D.3 Distillate for the Goldfields

The Free into Store price of distillate at 107.808 Acpl for Parkeston applies after applying a road freight cost of 5.93 Acpl to Parkeston. This equates to a diesel price of $0.980/litre ex GST for Parkeston. After deducting 40.29c excise and applying a calorific value of 38.6 MJ/litre, this equates to $14.95/GJ for Parkeston. The Net Ex Terminal distillate price is assumed to be $13.56/GJ, hence the assumed distillate road freight to Parkeston is $1.39/GJ.

D.4 Fuel consumption

The start-up fuel consumption for the aero-derivative gas turbines was estimated as 3.53 GJ. For liquid firing, it is 3.54 GJ. An additional 5% of heat energy was allowed for start-up on distillate at Lower Heating Value which equates to 0.27% at Higher Heating Value. A 10% standard deviation was applied to these values with a normal distribution limited to 3.2 standard deviations.

Table D- 2 shows the steady state heat rates that were applied for the aero-derivative gas turbines. They were increased by 1.5% to represent typical degradation from new conditions. The temperature sensitivity of the heat rates was estimated from the run-up heat rate curves, and was less than 1% over the range 15°C to 41°C.

Table D- 2 Steady state heat rates for new and clean aero-derivative gas turbines (GJ/MWh HHV)

		% site rating			
Temp	**Humidity**	**100%**	**50%**	**33%**	**25%**
15°C	30%	10.584	11.776	13.066	14.100

The minimum load position has been extracted from the sampled data and the corresponding heat rate at minimum determined from Table D- 2. This heat rate at this minimum, including the temperature variability, results in a normal distribution with a mean of 12.062 GJ/MWh and a standard deviation of 0.828 GJ/ MWh. The mean has decreased and the standard deviation has increased since the 2014 and 2015 reviews, where both are based on the analysis of actual dispatch for the Parkeston units over the 2014 to 2015 calendar years.

D.5 Aero-derivative gas turbines – LM6000

The maximum capacity of the Parkeston machines varies during the year due to temperature and humidity variation. The maximum capacity was derived from historical dispatch information taking into account the seasonal time of year using a sinusoidal fitting function. In this way, the variation of the maximum output during the year is included in the uncertainty analysis. A sinusoidal curve was used to estimate the maximum dispatch and the error around this curve was added back to give an overall distribution of maximum capacity. The applicable distributions are provided in a confidential Appendix to AEMO and the ERA.

The variable O&M cost for aero-derivative gas turbines is based upon a maintenance contract price of $281.36/hour in December 2016 dollars as estimated and shown in the second column from the right in Table D- 3. These costs have been established after new price data from GE were provided and the $US exchange rate was applied. Jacobs has applied economic time based discounting for the major overhaul components and the logistics costs split between scheduled and unscheduled maintenance to calculate a discounted cost of $174.08/hour. This is escalated to $175/hour in December 2016 dollars.

Table D- 3 Basis for running cost of aero-derivative gas turbines —LM6000 (December 2016 dollars)

Overhaul Type	Number of hours trigger point for overhauls	Cost per Overhaul	Number in Overhaul Cycle	Cost per cycle	Cost per fired hour	Discounted Cost per fired hour
Preventative Maintenance	4,000 hrs, 450 cycles or annually, whichever first		18.709	$308,100	$6.16	$6.16
Hot Section Rotable Exchange	12500	$3,903,774	3	$11,711,322	$234.23	$116.30
Major Overhaul	50000	$6,506,290	1	$6,506,290	$130.13	$64.61
Shipping of Parts, Travel, Living Expenses of Maintenance Personnel, Extra				$507,491	$10.15	$5.69
Unscheduled Maintenance				$2,661,281	$53.23	$53.23
Consumable Day-to-Day Maintenance (lube oil, air filters, etc)				$387,344	$7.75	$7.75
			Total:	$22,081,829	$441.64	$253.74

Source: Jacobs data sourced from manufacturers and analysis of discounted value based on 22.7 starts/year

Aero-derivatives have a minimum start-up cost equivalent to about one running hour. However, under this pricing structure, this additional impost may be ignored as immaterial.

Table D- 4 shows the assessed variable O&M cost based on the historical operating regime for the aero-derivative gas turbine since January 2014. The weighted average is $6.64/MWh. The variable O&M cost is more stable, so Jacobs has not added uncertainty due to changes in starts per year or running hours.

Table D- 4 Assessed variable O&M cost for aero-derivative gas turbine – LM6000

Aero-Derivative Unit	Average Running Hours	Number of Starts / Year	Cost / Run	Average MWh per Run	Variable O&M Cost $/MWh
1	28.4	16.0	$5,033	688.0	$7.32
2	160.2	26.0	$28,361	4238.0	$6.69
3	165.0	26.0	$29,210	4478.1	$6.52
ALL UNITS	117.9	68.0	$23,197	3494.5	$6.64

It is considered that liquid firing of aero-derivative gas turbines doubles the frequency of the Hot Section Rotable Exchange every 12,500 hours. This increases the assessed discounted operating cost from $177/hour to $254/hour, a 43% increase.

D.6 Results

Table D- 5 compares the results for the aero-derivative gas turbines with the results shown above for the industrial gas turbines. It is evident that the costs remain substantially lower for the aero-derivative gas turbines.

Table D- 5 Analysis of Dispatch Cycle cost using average heat rate at minimum capacity

Sample	Aero-Derivative – LM6000		Industrial Gas Turbine	
	Gas	Distillate	Gas	Distillate
Mean	$141.72	$161.06	$195.60	$313.12
80% Percentile	$161.98	$206.94	$240.25	$403.70
90% Percentile	$174.49	$232.86	$278.81	$457.48
10% Percentile	$112.05	$89.89	$121.97	$171.16
Median	$139.34	$160.29	$185.42	$308.35
Maximum	$277.42	$390.23	$786.85	$1,039.10
Minimum	$83.62	$37.84	$40.65	$44.69
Standard Deviation	$24.52	$54.93	$68.12	$113.23
Non-Fuel Component $/MWh				
Mean	$20.08		$61.96	
80th Percentile	$22.68		$84.27	
Fuel Component GJ/MWh				
Mean	10.259		18.546	
80th Percentile	10.646		19.356	
Equivalent Fuel Cost for % Value $/GJ				
Mean	13.546		13.542	
80th Percentile	17.308		16.503	

Appendix E. Calculation of maximum prices using market dispatch to estimate heat rate impact

In selecting the appropriate Maximum STEM Price, an alternative approach is to consider revising the pricing model to take account of observed dispatch patterns instead of using the average heat rate at minimum operating capacity. That would require a change to the Market Rules. However, for cross-checking purposes, we have analysed the positon if the Market Dispatch Cycle Cost Method had been applied.

E.1 Methodology for Market Dispatch Cycle Cost Method

The Market Dispatch Cycle Cost Method was based on the following principles for output level during the Dispatch Cycle:

- The gas turbine unit would be loaded at maximum allowable rate to minimum generation level after synchronisation.
- The gas turbine would generate at no less than minimum capacity level until required to run down to zero just prior to disconnection. This would define the basis for a minimum allowable capacity factor for the Dispatch Cycle.
- If additional generation is required, the unit would ramp up to an intermediate level, hold that level and then run down to minimum and zero levels. The rate at which the generation would increase would be the rate that would get the unit to maximum output and then back again.
- For higher generation levels the gas turbine would ramp up to maximum output, hold at that level, and then ramp down to minimum generation.

The use of the heat rate at minimum capacity is slightly conservative relative to results that would be expected from more detailed analysis based on typical operations. However, the impact on the Maximum STEM Price assessment in this review is minimal at $1/MWh rounding to the nearest integer.

E.2 Treatment of heat rates

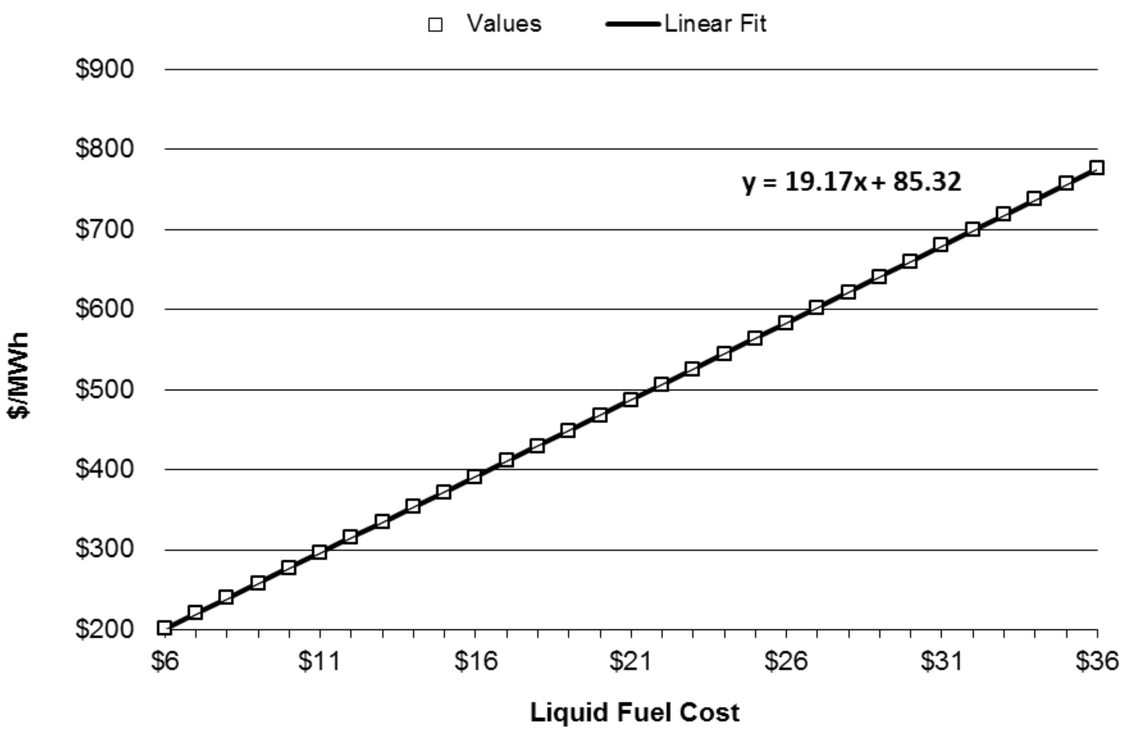
If we repeat the analysis of the Energy Price Limits, but develop the heat rates by using detailed dispatch modelling based on heat rate curves and probability distributions of capacity factor and maximum capacity derived from market data over the period from 1 January 2014 to 31 December 2015, with the same adjustment to frequency of unit starts, then we obtain the results shown in Table E- 1. This Market Dispatch Cycle Cost Method gives slightly lower heat rates at the 80% level for both Pinjar and the aero-derivative gas turbines.

Table E- 1 also shows the decomposition of the costs for distillate firing. The aero-derivatives have a higher fuel cost due to their more remote location. The non-fuel and equivalent heat rate terms for distillate firing were derived from the 80% cumulative probability values of cost versus distillate price over the range between $6/GJ and $36/GJ as explained in Section 2.5 for the 10,000 simulated values corresponding to each individual sample of cost. Again the relationship between the sampled values and the linear regression function was strong as shown in Figure E- 1.

Table E- 1 Analysis of Dispatch Cycle cost using Market Dispatch Cycle Cost Method

Sample	Aero-Derivative – LM6000		Industrial Gas Turbine	
	Gas	Distillate	Gas	Distillate
Mean	$142.37	$161.93	$194.16	$310.79
80% Percentile	$162.69	$208.32	$239.11	$401.05
90% Percentile	$175.11	$233.89	$278.32	$455.35
10% Percentile	$112.76	$90.20	$120.88	$168.68
Median	$140.04	$161.22	$183.13	$305.05
Maximum	$277.43	$386.75	$793.23	$1,060.83
Minimum	$82.60	$38.09	$40.95	$44.93
Standard Deviation	$24.35	$54.99	$68.80	$113.33
Non-Fuel Component $/MWh				
Mean	$22.16		$61.91	
80% Percentile	$22.76		$85.32	
Fuel Component GJ/MWh				
Mean	10.318		18.381	
80% Percentile	10.715		19.172	
Equivalent Fuel Cost for % Value $/GJ				
Mean	13.546		13.540	
80% Percentile	17.318		16.468	

Figure E- 1 80% probability generation cost with liquid fuel versus fuel cost (using Market Dispatch Cycle Cost Method)



E.3 Implications for margin with use of Market Dispatch Cycle Cost Method

If we adopt these higher values, then the margin of the price cap over the expected cost is 23.2% for the Maximum STEM Price and 10.9% for the Alternative Maximum STEM Price if based on $13.56/GJ Net Ex Terminal distillate price, as shown in Table E- 2 using rounded values. These margins reflect the current market and cost uncertainties[35].

Thus if we compare the assessed cost using the average heat rate at minimum capacity with the expected cost allowing for the Dispatch Cycles, then we obtain the comparison shown in Table E- 3. This would provide an effective margin of up to 22.4% over the expected cost, which is lower than the required heat rate assumption (accounting for rounding error). The margin for the Alternative Maximum STEM Price is 10.9% over the expected Dispatch Cycle cost.

Table E- 2 Margin analysis (Market Dispatch Cycle Cost Method) [36]

	Maximum STEM Price	Alternative Maximum STEM Price at $13.56/GJ[37]
Expected Cost	$194.00	$311.00
Market Dispatch Cycle Cost Based Price Cap	$239.00	$345.00
At Probability Level of	80%	80%
Margin	$45.00	$34.00
% Margin	23.2%	10.9%

Table E- 3 Margin analysis with use of average heat rate at minimum capacity using Market Dispatch Cycle Cost for the expected cost

	Maximum STEM Price	Alternative Maximum STEM Price at $18.17/GJ
Expected Cost (Market Dispatch Cycle Cost)	$196.00	$313.00
Proposed Price Cap (Min Heat Rate)	$240.00	$347.00
At Probability Level of	80%	80%
Margin	$44.00	$34.00
% Margin	22.4%	10.9%

[35] Note that the expected value of $311/MWh for the Alternative STEM Price allows for the modelled uncertainty in the distillate price.
[36] Rounded to the nearest $/MWh.
[37] Net Ex Terminal.